ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM
A PROGRESS REPORT ON RPI 1529

MIT Energy Laboratory, Utility Systems Program
with
Stone and Webster Engineering and
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Section 1

INTRODUCTION

Electric utility planning has undergone significant changes during the past decade. From a period in which capacity expansion planning was based upon cost minimization techniques operating in an environment of relative certainty, expansion planning has evolved into a complicated arena. Management decisions now require weighing short- and long-term policies for supplying electrical power, balancing present certainties in generating alternatives with future uncertainties in new technologies, as well as analyzing complex environmental regulations and siting constraints in the utility's decisions to develop generating capacity. In addition, there is now far greater uncertainty in both the rate of growth of demand for electrical power and the potential for power generation by both small and large cogenerators.

Within this background of evolution and uncertainty EGEAS is planned to provide a state-of-the-art flexible software system for electric utility capacity expansion planning which will utilize a common data base and control program for both a set of core analysis alternatives and a set of modular, advanced feature packages. The system will be based upon selected existing operating and capacity expansion software as well as upon software developed during the length of the contract.

EGEAS is based upon two currently available but independent optimization packages, GEM (linear programming) developed at MIT and OPTGEN (dynamic programming) developed by Stone and Webster Engineering Corporation. In addition, EGEAS will utilize the operating system model SYSGEN developed at MIT. The complete EGEAS structure will incorporate a third optimization algorithm, Generalized Benders' decompositon, and two other analysis options, Year-End Optimization and Prespecified Expansion

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Pathway as portions of the overall system giving five analysis options. The data structure of the MIT GEM model will be expanded and evolved to be accessed by all five analysis options.

In addition to the core structure, EGEAS will contain a highly flexible interface structure to incorporate submodeling capability in analysis of renewable energy technologies such as solar and wind; storage technologies; financial data beyond that traditionally included in capacity expansion models; two region interconnections; environmental screening capability and alternatives for load modification. Each of these advanced features are to be developed with interface characteristics capable of being adapted to varying levels of detail in modeling sophistication. While not included as a portion of the current development work the modeling structure is designed such that at a later date a portion of or the total EGEAS structure can be made interactive. A description of the objectives of each of the major components of EGEAS can be found in Section 11.2. These objectives are the yardstick against which the success of EGEAS will be measured.

The report which follows covers the progress during the first four months of the project. It summarizes the review and analysis of the utilities' requirements for capacity analysis tools, presents the status of development of the EGEAS data base and optimization development, reviews the work to date on development of advanced features for financial analysis, storage, interconnection, load modification, and other concerns such as enviroronmental issues. The report has been written to represent a cut through work in progress. It is however intended to be a stand alone document that will allow the reader sufficient information both to understand the underlying structure of EGEAS and to evaluate the first steps in carrying out its overall objectives.

Throughout the project we will be maintaining a consistent vocabulary. The two most significant terms used within the report are:

A. Expansion Alternative: The set of data developed to describe one of the choices available to the utility for meeting its long-range planning requirements. This includes such data as:

Physical Description

Financial Characteristics

Environmental Restrictions/Costs, etc.

B. Analysis Option: One of the five optimizing/nonoptimizing tools
included within EGEAS.

Linear Programming

Dynamic Programming

Generalized Benders' Decomposition

End Year Optimization

Prespecified Expansion Pathway

Section 2

UTILITY NEEDS ASSESSMENT

2.1 INTRODUCTION

The original EGEAS proposal contained an overall concept that was based
on combining the past experience of MIT and Stone and Webster in capacity
expansion planning to meet the future planning needs of the utility
industry. Prior to the final design of the EGEAS system a set of
discussions were held with advisory board members to assess their
projected modeling needs into the decade ahead. A number of such
discussions have taken place (see Appendix B for a complete listing);
this chapter summarizes the results of these conversations and discusses
briefly the changes in EGEAS proposed as a result of this needs
assessment. This chapter does not attempt to summarize explicitly the
statements of the individuals or institutions contacted and should not be
interpreted as a consensus of their opinions. It also does not purport
to cover all of the issues discussed in the meetings but rather
concentrates upon those issues which arose several times either at the
suggestion of MIT/SWEC or the host utility. Everyone viewed the problem
areas discussed from a different perspective and, quite naturally, would
like to see EGEAS evolve in somewhat different directions. This chapter
represents an MIT/SWEC perspective which takes into consideration the
basic building blocks, GEM and OPTGEN.

Discussions will be presented in terms of the following categories:
- Common Data Base, Multiple Options
- Renewable Technologies, Nonexpansion Alternatives
- Financial
- Environmental
- Interconnections

- Sensitivity Analysis, Uncertainties
- Input/Output
- Maintenance of Code, User Training

This chapter concludes with a summary of those points and recommendations which will affect the final shape of EGEAS.

2.2 COMMON DATA BASE, MULTIPLE OPTIONS

The basic philosophy underlying EGEAS is to have multiple expansion analysis options built into the codes, all working from a common data base.

In general, the discussions indicated that the common data base, multiple options concept was potentially extremely desirable although there was some concern expressed about its feasibility. A major concern was expressed on whether inexperienced users could and/or would make intelligent choices among the various options and thereby correctly model their expansion problem. With the present design philosophy it is clear that inexperienced users will be able to misuse the options and generate bad results either in terms of wasting computer time—choosing too sophisticated a modeling procedure--or worse, generating invalid output by using an overly simplified option that does not yield acceptable results for the problem of concern.* Safeguards will be considered, though, as discussed below, user education is likely to be the more efficient solution.

2.3 RENEWABLE TECHNOLOGIES, NONEXPANSION ALTERNATIVES

EGEAS is designed explicitly with the ability to study renewable technologies with a particular emphasis on solar.

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*It should be noted that even a computer code with only one fixed option can also be misused if put in the hands of an inexperienced user, because if there is only option, the user may be tempted to apply it to answer all problems.

The discussions strongly emphasized the importance and need for an ability to study renewable technologies and it was stated that such a capability would make EGEAS much more desirable than any existing computer code. There was also a particularly strong expression of a need for utilities to be able to explore nonexpansion alternatives, such as load management, customer generation, and fuel switching.

As a result of these discussions and our own thought in this area, we propose to restructure our general approach and software development so that nonexpansion alternatives and renewable technologies are given equal weight in the overall concept along with traditional, central-station fossil, nuclear, etc.. This does not imply a need to start all over with the EGEAS concept but it does indicate a real change in point of view and philosophy, as was corroborated during the January 1980 review meeting.

2.4 FINANCIAL

The EGEAS project is funded to provide a paper study which will describe alternatives on how financial considerations can be modeled and factored into the EGEAS structure. Furthermore, the EGEAS data base structure is to be developed so that a financial modeling capability can be added later.

The discussions showed that the degree and type of interactions presently existing in utilities between expansion analysis and financial modeling are highly variable (ranging from being very important to being effectively nonexistent). It was universally agreed that incorporation of some financial modeling capability within the EGEAS structure would be highly desirable. However, there was no clear indication of the best alternative. Chapter 6 presents initial proposals for incorporation of financial considerations into the EGEAS optimization options.

2.3 ENVIRONMENTAL

EGEAS is to have an environmental impact modeling capability based on the concept of generic sites which have specific air, water, land use, etc. characteristics and limitations but which are not explicitly located.

The discussions did not emphasize or concentrate on environmental issues; there was general agreement that the generic siting approach was the most functional and implementable way to proceed within the EGEAS structure.

2.6 INTERCONNECTIONS

EGEAS is to be developed to have one or more forms of interconnected system modeling capability.

The discussions indicated that interconnected modeling capability is important to many utilities. However, the technical issues on how this modeling capability should be implemented were not covered. Chapter 9 presents the current approach for EGEAS.

2.7 SENSITIVITY ANALYSIS, UNCERTAINTY

EGEAS is to have automatic sensitivity analysis capabilities in order that the user may analyze how uncertainties in inputs propagate through the optimization and affect outputs.

The discussions indicated a wide variation in the types of sensitivity analyses presently being carried out by the utilities with apparently no one attempting to follow a formalized procedure. There appeared to be agreement that automatic sensitivity analysis would be useful. It was not clear whether or not it is desirable to provide "ultimate decision makers" with simple, single solutions or with a range of solutions that have uncertainty associated with them. The value to the decision maker of working within a formal, probabilistic framework was not clear. Chapter 10 discusses uncertainty and sensitivity analysis in greater depth.

2.8 INPUT/OUTPUT

EGEAS is to be explicitly coded only to run in a bulk process fashion. However, the software is to be developed such that an interactive capability can be added later if desired.

The discussions emphasized the need for an input process that is simple, self-correcting, error-detecting, etc. There was real fear that inexperienced or sloppy users would generate bad output unless the input procedures were "almost foolproof." A relatively small amount of time was spent discussing output options although this is, of course, an important area in the overall success of the EGEAS project.

2.9 MAINTENANCE OF CODE, USER TRAINING

The original EGEAS proposal and the present EGEAS contract does not cover or consider the maintenance of the code and user training requirements after the code has been developed and delivered.

The discussions indicated serious concern on how the code would be maintained and users trained. It was felt that one institution should be responsible and that this would not be a trivial task. If the code is as successful as it is intended to be, various users will develop their own specific variations on the options, and hence after a while there will be multiple versions of EGEAS. Some mechanism to maintain cohesion and to facilitate exchanges between users will be needed.

2.10 SUMMARY AND RECOMMENDATIONS

Two main points and issues came from the utility needs discussions. The first main point is that it is necessary, in all likelihood, to modify and restructure our thinking and code development so that renewable generation technologies and nonexpansion alternatives are given equal weight in the development of EGEAS along with the more conventional central-station, fossil, nuclear, pumped hydro, hydro, etc. This by no

means implies a starting over of the concepts but it does imply a change in emphasis and philosophy.

The second area of concern centers on the basic philosophy of EGEAS being a multiple option software package; the problems associated with developing appropriate intput/output data interfaces for such a code; and the dangers of placing such a sophisticated software package in the hands of what could be relatively inexperienced users. This, combined with the express need for someone to be in charge of maintenance of the code, leads to the following recommendation.

EGEAS will remain a multi-option code. The input and output will be made as versatile as possible consistent with the constraints of a bulk processing computer code. Some generalized error-detecting procedures will be incorporated for the inputs but no hard, problem-specific constraints and tests will be incorporated. After the code is delivered, EPRI should specify one organization with both software and generation expansion analysis technology capabilities to maintain the code and to conduct user training sessions. This organization should also furnish services whereby they will talk with specific utilities to learn their specific needs, and on the basis of those needs determine which particular option or combination of options are most appropriate for that utility. The maintenance organization will, for a small fee, develop an input capability which is tailored specifically to the needs of the specific utility and the options that are appropriate to that utility. The actual computer code given to that utility would then be much safer, much smaller, have fewer options, and would have a more foolproof input capability. This organization could also adapt the output software needs of particulary utilities. Such a function could be located at the Software Center at EPRI, at an individual lead utility, or within a private firm or organization.

In summary, the Utility Needs Assessment phase of the EGEAS project focused the project more tightly to its basic structure but did not serve to alter dramatically the perceived EGEAS structure or modeling requirements other than as stated above. These points have been discussed in greater detail at the January 1980 review meeting.

Section 3

REVIEW OF SELECTED UTILITY PLANNING MODELS

3.1 INTRODUCTION

The objective of this chapter is a review of selected capacity expansion models. The review of six representative, state-of-the-art capacity expansion models by S. Lee et al., (8) is attached as an appendix to this report. Lee et al. is the result of an extensive study which need not be duplicated. We therefore assume that this chapter will be read as an addition to the review of WASP, OPTGEN, U. Mass Model, MIT Model, PUPS and MNI-GRETA by S. Lee et al.

3.2 SCOPE

Six capacity expansion models are briefly presented here, selected because they include features that represent the state of the art and deal with issues of cardinal interest to the EGEAS project, like system reliability, uncertainties, financial considerations, environmental effects, interconnections, transmission costs, treatment of end effects, and siting. The following models will be compared in a matrix of attributes followed by short individual model descriptions:

o GMP - A Generation Mix Planning package which is an adaptation of WASP by the Southern Company.

o WAGP - An automatic expansion program recently developed by Westinghouse which utilizes a combination of screening and branch and bound logics to select the optimum capacity expansion plan.

o OGP – An Optimized Generation Planning program developed by General Electric which utilized operation models together with a myopic one-future-period (year) optimization technique repeated to describe a 20-year capacity expansion plan.

o O/U – A model developed by Decision Focus, Inc. for EPRI with the objective of studying costs and benefits of Over/Under Capacity in Electric Power Systems Planning.

o The RPI model – An energy appraisal model developed at Rensselaer Polytechnic Institute which utilizes an LP formulation to study the effects of environmental constraints on the optimal capacity expansion plan.

o The BNL – REFS Model – A siting LP model developed by Brookhaven National Laboratory to allocate capacity to counties based on environmental impacts, transmission, and coal transportation costs.

3.3 MATRIX OF INTER MODEL ATTRIBUTE COMPARISON (attached)

3.4. MODEL SUMMARIES

3.4.1 The Generation Mix Planning Package (GMP)

The Generation Mix Planning Package (GMP) is an adaptation of the Wien Automatic System Planning Package (WASP) program developed by the Tennessee Valley Authority (TVA). GMP evaluates alternative generation sources from three standpoints: reserve or reliability, operating cost, and investment cost. The basic structure of the Generation Mix Planning Package is represented in Figure 3.1.

The Generation Mix Planning Package was developed as a series of six separate programs to allow the user to monitor the step-by-step results of data gathering and processing during the conduct of a generation mix study. Each program may be run as a "stand-alone" program, or any number

MODEL

ATTRIBUTE	GMP	WAGP	OGP	O/U	RPI Model	BNL-REFS
Solution Meth.	Dynamic Pr.	Screening & Branch & bound	Myopic one future period opt.	Prespecified mix.	LP (simult. min. cap. and O&M)	LP
Prob. Size	Limited	Limited	Limited	Limited	Limited	Limited
Available subopt. plans	Under devel- opment	NO	NO	NO	NO	NO
Reliability Est.	LOLP Probabilistic	Options, determ. or probabilistic LOLP	LOLP Probabilistic	Unserved Energy Probabilistic	*	NONE
System Reliab.	Exogenous	Exogenous	Exogenous	Exogenous	Exogenous	Reserve Marg.
Variable Costs	Probabilistic Prod. costing	Determ. or Prob. Prod. costing	System Operation simulation*	Probabilistic Prod. costing	Sequential Multiple Objective Technique	Exogenous
End Effects Accounting	NO (?)		NO	YES	*	NO
Financial Considerations	YES, post plan selection interphase with financial model	YES, Constraints	YES, post plan selection inter- phase with financial model	YES, detailed	NO	NO
Environmental Effects		YES, Constraints	Reporting only	YES, objec- tive function	YES, objec- tive function	YES, Constraints

3.3. Matrix of Inter Model Attribute Comparison

*insufficient information available

MODEL

ATTRIBUTE	GMP	WAGP	OGP	O/U	RPI Model	BNL-REFS
Siting	NO	NO	NO	NO	NO	YES
Hydro Alt.	YES	YES	YES	*	YES*	YES
Storage	YES	*	YES	*	NO*	YES
Thermal Alt.	YES	YES	YES	YES	YES	YES
Unconvent. Alt.	NO	NO	NO	NO	NO	NO
Inter-connection	YES	*	NO	NO*	NO*	NO*
Comput. Burden	High	Moderate to High	Moderate to Low	Moderate	Moderate	Moderate

3.3. Matrix of Inter Model Attribute Comparison (continued)
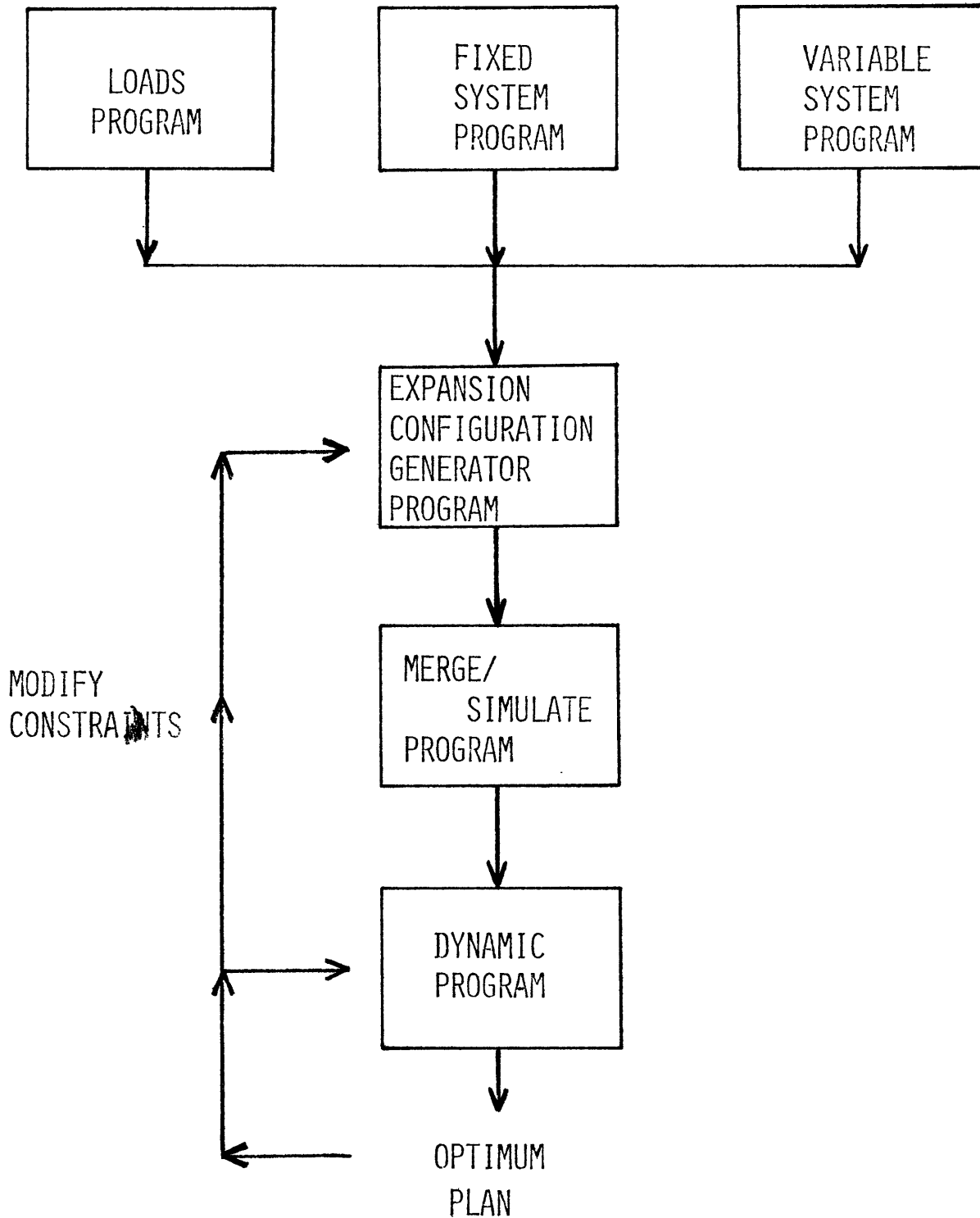
*insufficient information available

Figure 3.1. Generation Mix Planning Program Package

of programs may be run sequentially as individual steps in a production job stream.

The Expansion Configuration Generator Program allows the planner to direct the area of study to expansion alternatives which he believes to be most economic or necessary to satisfy defined constraints. This can be accomplished by specifying minimum and maximum reserve requirements, setting restrictions on the periodic and annual loss-of-load probabilities, and/or limiting the minimum or maximum number of units of a particular expansion alternative that can be installed in any given year. This program forms a list of all allowable system configurations, based on constraints defined for each year in the study.

The Merge and Simulate Program calculates total yearly operating costs of each of the configurations generated by the Expansion Configuration Generator program using a probabilistic simulation technique.

Files generated by the Fixed System, Variable System, Expansion Configuration Generator, and Merge/Simulate programs are then used by the Dynamic Program to determine optimal generation expansion policies. A dynamic programming algorithm is used to calculate the best expansion policy.

3.4.2 The Automatic Expansion Program (WAGP)

The automatic expansion program (WAGP) has been recently developed by Westinghouse. It uses a combination of screening and branch-and-bound logics to perform the optimal capacity selection task. The program can handle up to seventy unit addition types with varying running times, depending on the subalgorithms used. It is modular by design and allows the user to choose from a range of algorithms depending on the accuracy of the answer desired and the assumptions built into the input data. Thus a deterministic or probabilistic production costing routine may be used, while on the capacity selection side a global optimization or a year-by-year optimization algorithm may be chosen.

The objective function minimized is the present worth of capital and operating costs, while transmission costs may be included if desired. Constraints include reliability, retirement-commitment, production, cash flows, environmental, and mix-constraints. The interaction of the seven modules contained in WAGP is depicted in Figure 3.2.

3.4.3 The Optimized Generation Planning Model (OGP)

The Optimized Generation Planning Model has been developed by General Electric and employs a year-by-year optimization routine which ranks various alternatives to work through a 20-year expansion plan.

Three submodels dealing with reliability evaluation, production costing, and investment costing are used in an iterative fashion in the process of determining minimum cost additions of generating capacity in each year. The structure of OGP and the interface of the submodels is presented in Figure 3.3.

3.4.4 The Over/Under Capacity Model (O/U)

The O/U model was developed for EPRI by Decision Focus, Inc. during a study of costs and benefits of Over/Under capacity in electric power system planning.

The study emphasizes decisions concerning the alternative levels of capacity additions required to meet uncertain future demand. Alternative levels of capacity additions can be characterized by a range of alternative planning reserve margins. The effects of alternative planning reserve margins are captured in the model that computes such terms as outage cost, environmental cost, and revenue requirements (fixed and variable costs charged to customers).

The structure of the computer model is summarized in Figure 3.4. As illustrated, the model consists of four main component models: the demand uncertainty, capacity expansion decision, electric system, and the consumer preference models. The overall model is used to evaluate
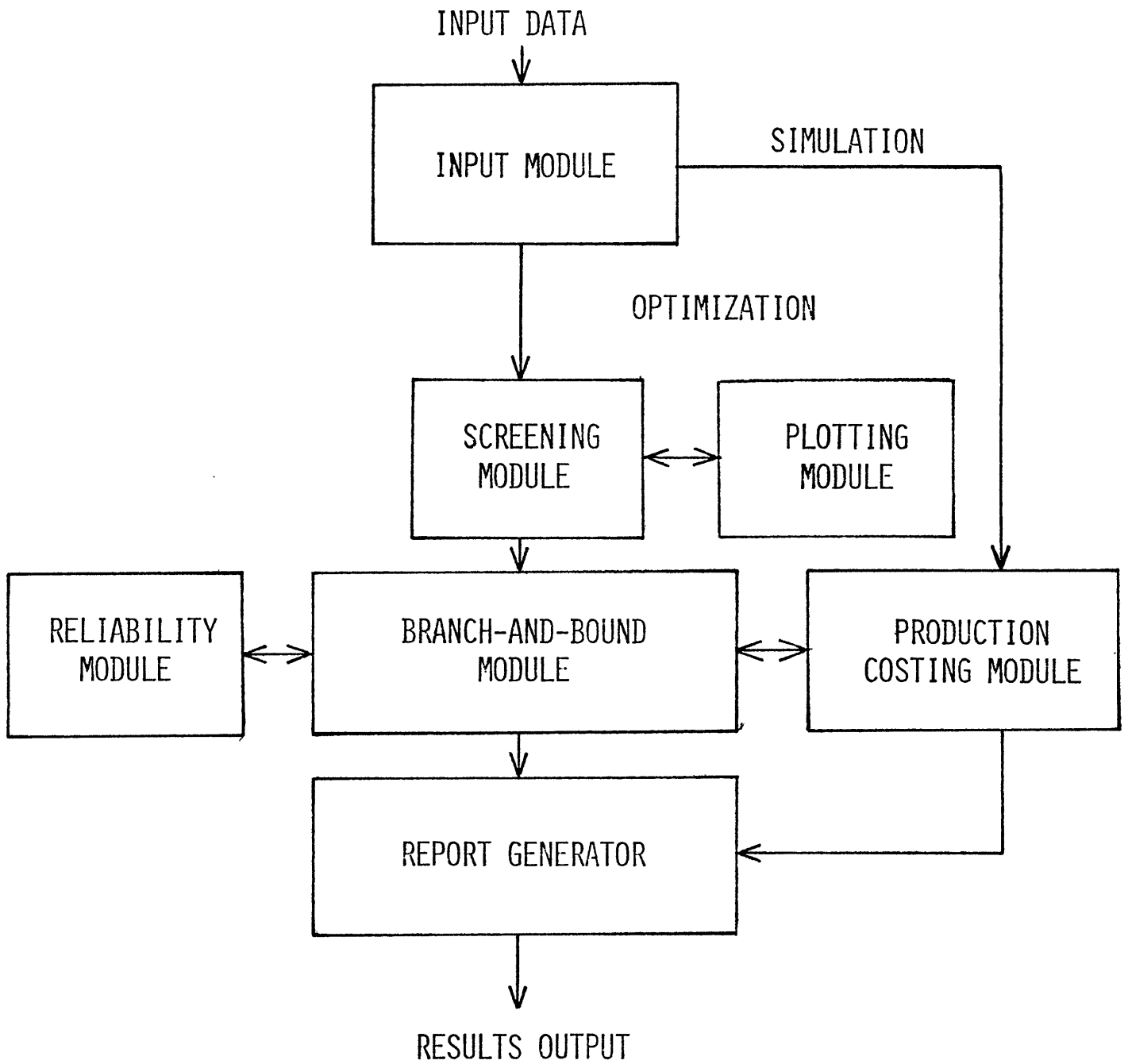
INPUT DATA

```
                    ┌─────────────────────┐
                    │                     │──────── SIMULATION ──────┐
                    │    INPUT MODULE     │                          │
                    │                     │                          │
                    └─────────────────────┘                          │
                              │                                      │
                         OPTIMIZATION                                │
                              │                                      │
              ┌──────────────────┐    ┌──────────────────┐           │
              │   SCREENING      │◄──►│    PLOTTING      │           │
              │    MODULE        │    │     MODULE       │           │
              └──────────────────┘    └──────────────────┘           │
                              │                                      │
┌──────────────┐   ┌──────────────────────┐   ┌──────────────────────┐
│ RELIABILITY  │◄─►│   BRANCH-AND-BOUND    │◄─►│    PRODUCTION         │
│   MODULE     │   │      MODULE           │   │  COSTING MODULE       │
└──────────────┘   └──────────────────────┘   └──────────────────────┘
                              │
                   ┌──────────────────────┐
                   │   REPORT GENERATOR    │◄──────────────────────────
                   └──────────────────────┘
                              │
```
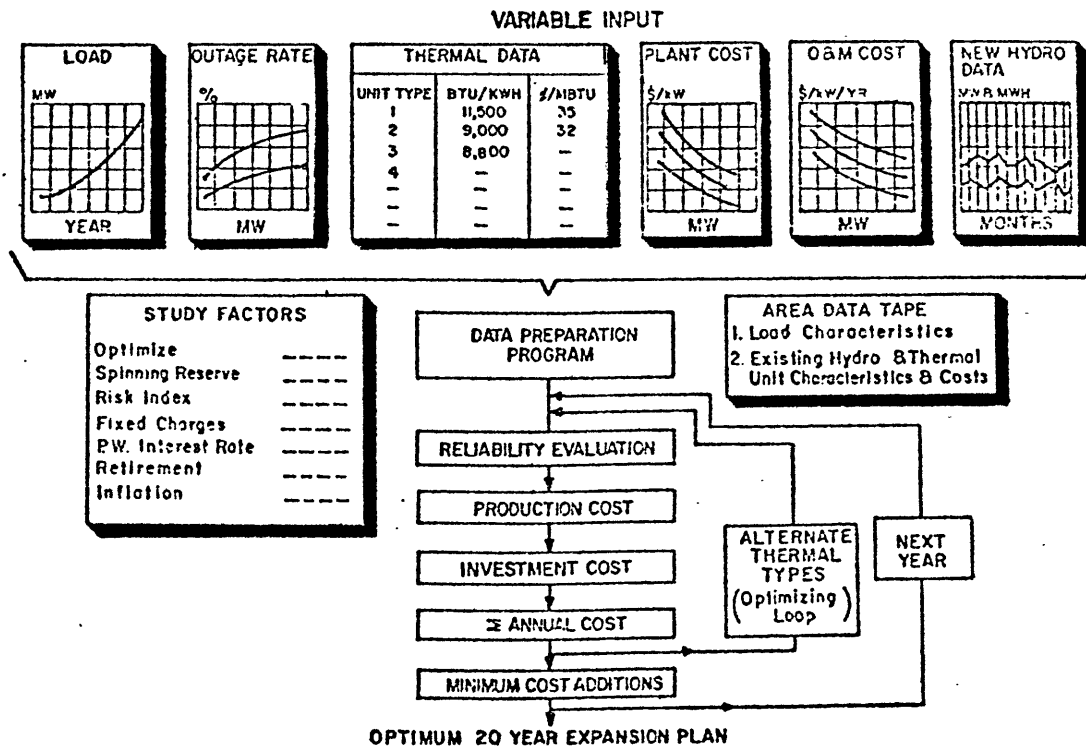
RESULTS OUTPUT

Figure 3.2. WAGP Structure

VARIABLE INPUT

LOAD	OUTAGE RATE	THERMAL DATA			PLANT COST	O&M COST	NEW HYDRO DATA
MW	%	UNIT TYPE	BTU/KWH	$/MBTU	$/kW	$/kW/YR	KWR.MWH
		1	11,500	35			
		2	9,000	32			
		3	8,800	—			
		4	—	—			
		—	—	—			
		—	—	—			
		—	—	—			
YEAR	MW				MW	MW	MONTHS

STUDY FACTORS

Optimize	————
Spinning Reserve	————
Risk Index	————
Fixed Charges	————
P.W. Interest Rate	————
Retirement	————
Inflation	————

DATA PREPARATION PROGRAM

AREA DATA TAPE
1. Load Characteristics
2. Existing Hydro & Thermal Unit Characteristics & Costs

RELIABILITY EVALUATION

PRODUCTION COST

INVESTMENT COST

Σ ANNUAL COST

ALTERNATE THERMAL TYPES (Optimizing Loop)

NEXT YEAR

MINIMUM COST ADDITIONS

OPTIMUM 20 YEAR EXPANSION PLAN

Figure 3.3. Optimum Generation Planning Structure
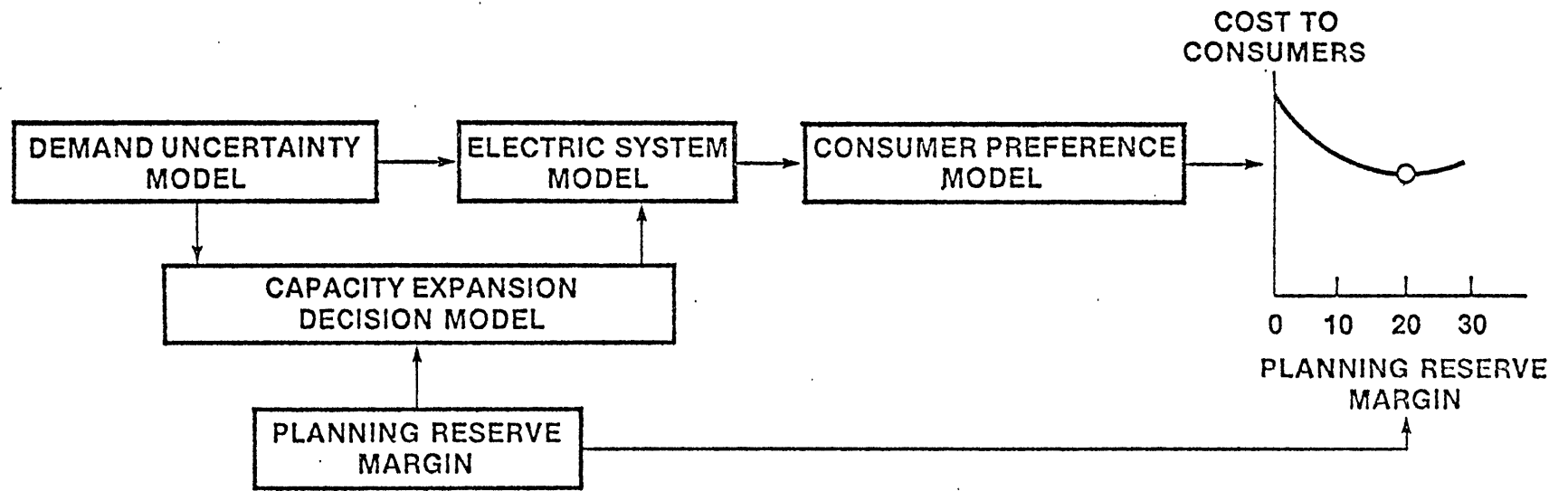
Figure 3.4. Overview of the O/U Planning Model Structure

different planning reserve margins shown at the bottom of the figure. The model computes the total cost to consumers of various levels of planning reserve margin and summarizes this information in the form of a U-shaped curve, as illustrated at the right of the figure.

Capacity expansion decisions and consumer cost calculations are both based on an explicit representation of demand uncertainty. Instead of assuming a single demand forecast for each future year, as is the current practice in power system planning, the demand uncertainty model explicitly models a large number of possible demand trajectories over time that specify the high, medium, low demand growth outcomes in each future year. The range of uncertainty is determined using a formal interview process for quantifying expert information in terms of probabilities.

Based on the range of demand uncertainty, the resolution of that uncertainty over time, the input planning reserve margin, and an input planning technology mix, the capacity expansion decision model simulates the capacity decision process over time. Flexibility in the planning process to respond to higher or lower than expected demand growth is explicitly represented as new units pass through separate planning stages of studies, licensing, and construction. For each planning reserve margin, the capacity decision model simulates this planning process in each time period of each possible demand trajectory.

Based on the resolution of demand uncertainty and the installation of new capacity over time, the electric power system and consumer preference models compute the cost to consumers. The electric system model has two parts. First, a probabilistic production simulation model computes system variable costs over time using a method currently employed by many utilities. Outage energy and environmental effects are also computed. Second, a fixed-charge (financial) model computes the fixed charges to customers over time. The fixed charges may include extra financial charges which customers must bear if the capacity expansion plans under evaluation strain the utility's financial resources.

In the consumer preference model, critical subjective value judgments, which ultimately cannot be avoided in capacity planning, are explicitly represented and used to determine a single "bottom line" consumer cost. To determine this cost, trade-offs must be made among the cost of electricity (fixed plus varable costs), outage energy, and environmental effects; among consumers costs in different time periods; and between certain and uncertain consumer costs.

3.4.5 The Energy Appraisal Model Developed at RPI

The objective of the Energy Appraisal Model developed at Rensselaer Polytechnic Institute is to find a generation expansion plan for an electric system which minimizes the present worth of power production costs, subject to a set of constraints, including (among others)

1. Coal and/or oil consumption,
2. Emissions of a number of pollutants,
3. Expected emission-related mortalities, and
4. Expected property damage;

or which minimizes one of these listed factors without increasing the present worth of power costs by more than a specified percentage above its value from a prior run.

The algorithm used is a linear program (LP) which optimizes both generation capacity expansion and operating policy simultaneously, using a "sequential multiple objectives" technique. A set of routines disaggregates some of the inputs.

Input requirements include 12 categories of aggregated supply variables (including the fuel costs, capital costs, O and M costs, forced outage rate, and plant outage rate for each expansion candidate) and two categories of demand variables (growth rate of peak load, load duration curves).

The output capabilities consist of a set of factors specifying the expansion plan and operating characteristics selected, including:

1. Installed generation schedule by year.
2. Operating schedule by year for each plant type.
3. Coal consumption schedule.
4. Oil consumption schedule.
5. Expected emission-related mortalities.
6. Expected property damage.

(The last 4 factors are calculated as simple functions of the first 2.)

3.4.6 The BNL-REFS Model

The Regional Energy Facility Siting Model developed at Brookhaven National Laboratory focuses on determining general future siting patterns for power generating facilites. It allocates generating capacity to counties based on a minimization of coal transportation and transmission costs and subject to constraints of physical resources and environmental quality.

The model uses a linear programming algorithm, and has the following input requirements:

- o Generation mix,
- o Demand per county,
- o Inter-county transmission costs,
- o Existing railroad capacity limits by gateway county,
- o Stream flows,
- o Environmental standards (NSPS), and
- o County Exclusions.

The output capabilities consist of generation capacity by generation type (and cooling technology) for each county. Mapping capabilities are under development.

3.5 CONCLUSIONS

The following conclusions could be drawn from the comparison of the models summarized above.

- A modular structure allowing either independent use of code components to perform partial analyses or choice of the level of detail/accuracy to be applied to generation expansion analysis is a desirable feature. GMP and WAGP seem to make good use of that feature but it is not clear whether all modules can operate from a common data base.

- Solution methods are related to trade-offs between accuracy in the problem's representation/solution and the computational burden. Simplification in the optimization routines often allows increased detail in dealing with other than strictly engineering-economic aspects of capacity expansion. For example, the O/U model looks at financial considerations and deals with uncertainties and consumer preferences at a relatively advanced level of detail. The price for doing that, however, is the use of a simplified simulation routine to determine new capacity additions.

- None of the models reviewed has the capability of providing the user with suboptimal plans. This capability is related to the solution method used. Dynamic programming as well as similar algorithms, which construct an enumeration of alternatives before selecting the optimal one, are more apt to modification so that near-optimum plans are described.

- System reliability estimates are internal to those models that utilize a separate production simulation model. The same holds for variable costs.

- Environmental effects are treated in detail and are embedded in the optimal plan selection algorithm only by the RPI and the BNL models. These models, however, utilize linear programming to derive the optimal plan, and thus contain a limited representation of production costing considerations.

- Various other aspects of interest in capacity expansion analysis like transportation costs, uncertainties, siting, pumped hydro and storage, interconnections, transmission and distribution are addressed by some models, but no model exhibits adequate representation of all of them.

- Unconventional alternatives like solar and wind energy transformation, load management, cogeneration, and others which are not related to generation capacity with constant availability, are not addressed by any of the models summarized. A survey of production cost models has pointed at two models which have been modified to handle solar energy capacity additions; they are SYSGEN developed at MIT and PROMOD developed by Energy Management Associates and augmented with a solar model, designed as a cooperative effort with Stone and Webster and Southern California Edison Company. The incorporation of solar energy alternatives into a capacity expansion model may certainly be achieved through the use of a proper production cost model as part of a generation expansion code. Chapter 7 of this report presents the general approach to be implemented in EGEAS which will allow analysis of unconventional alternatives.

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Section 4

DATA BASE DESIGN

This chapter focuses on the issues and trade-offs to be considered in the design of the EGEAS data base. A very general data structure is then presented. Some of the issues presented here stem from discussions held during the Utility Needs Assessment Task; others from the Review of Other Models and the Code Breakdown Tasks.

4.1 DESIGN CONSIDERATIONS

Ideally, the data base designed for a given model should contain only the parameters which are necessary and sufficient to allow for the analysis to be performed. The structure and detail should reflect the certainty of the available input data and the modeling assumptions to be used.

The EGEAS data base is particularly difficult to design in this regard, since multiple models of similar scope are to access this data base, each with drastically different model assumptions and each with different levels of detail required in various areas. Further, multiple independent users are to access this model, each of whom has different data availability as well as different types of analyses to be performed. The tendency to be "all things to all people" must be mitigated by finding unifying data base assumptions and requirements and by externalizing wherever possible (with well-defined interfaces) issues relating to but not directly within the scope of usual expansion planning analysis performed by utility system planners (e.g., financial/corporate modeling, demand forecasting, etc.). Special considerations required by specific users cannot be dealt with as design constraints but rather as a lower-priority design consideration.

The following section discusses some of the design considerations used in structuring the EGEAS data base.

4.2 SCOPE

EGEAS is designed to focus on the analytic needs of the utility system planner. Growth patterns, the world oil situation, increased regulation, growing levels of interconnection, environmental issues, the changing financial picture, make a utility system planner's job closer to one of finding any feasible capacity expansion plan at all as opposed to one of finding a near optimal, risk-averse solution out of a set of many feasible ones. These considerations which lie outside the conventional analyses for reliability analysis, production cost simulation, and standard engineering/economics must in some way be addressed by EGEAS. Conversely, the costs, complexity, and other problems associated with massive, diverse data requirements cannot be justified in many of the analyses which planners might perform. (A utility with predominantly hydro capacity might not be interested in environmental issues regarding thermal emissions from nuclear power plants.)

To minimize the impact on the basic EGEAS data base and increase flexibility, increases in scope will be handled by creating interface extensions of the data base which can be turned on or off in much the same way as the GEM data base handles the environmental extension to the conventional expansion planning parameters. Figure 4.1 shows the general structure of the GEM data base. GEM could be run as a conventional planning tool if given only the data structure of the economic branch of the tree. For environmental issues to be handled, the environmental data structure would have to be established in core. No change to the economic structure would be incurred by adding the environmental structure. Figure 4.2 shows how the programs access the data base. The areas inside the dotted line represent the environmental portions of the GEM model.

```
                              GEM INPUT
                              PARAMETERS
                                  |
          ┌───────────────────────┴──────────────────────────┐
      ECONOMIC                                           ENVIRONMENTAL
          |                                                   |
  ┌───┬───┼───┬───────┐                          ┌────────────┼────────────┐
CUSTOMER  │ ENVIRONMENTAL │ EXISTING │          SITE          │          POLLUTION
      │   RESTRICTIONS   │  SYSTEM  │          DATA    ENVIRONMENTAL        LIMITS
  MANAGEMENT      ALTERNATIVES   FUEL              │      FUEL DATA
                      │       RESERVES            │
              ┌───────┴───────┐          ┌────────┴────────┐
            BASIC         ABATEMENT    AMBIENT            EPA
            PLANT           DATA     CONDITIONS        STANDARDS
            DATA
```
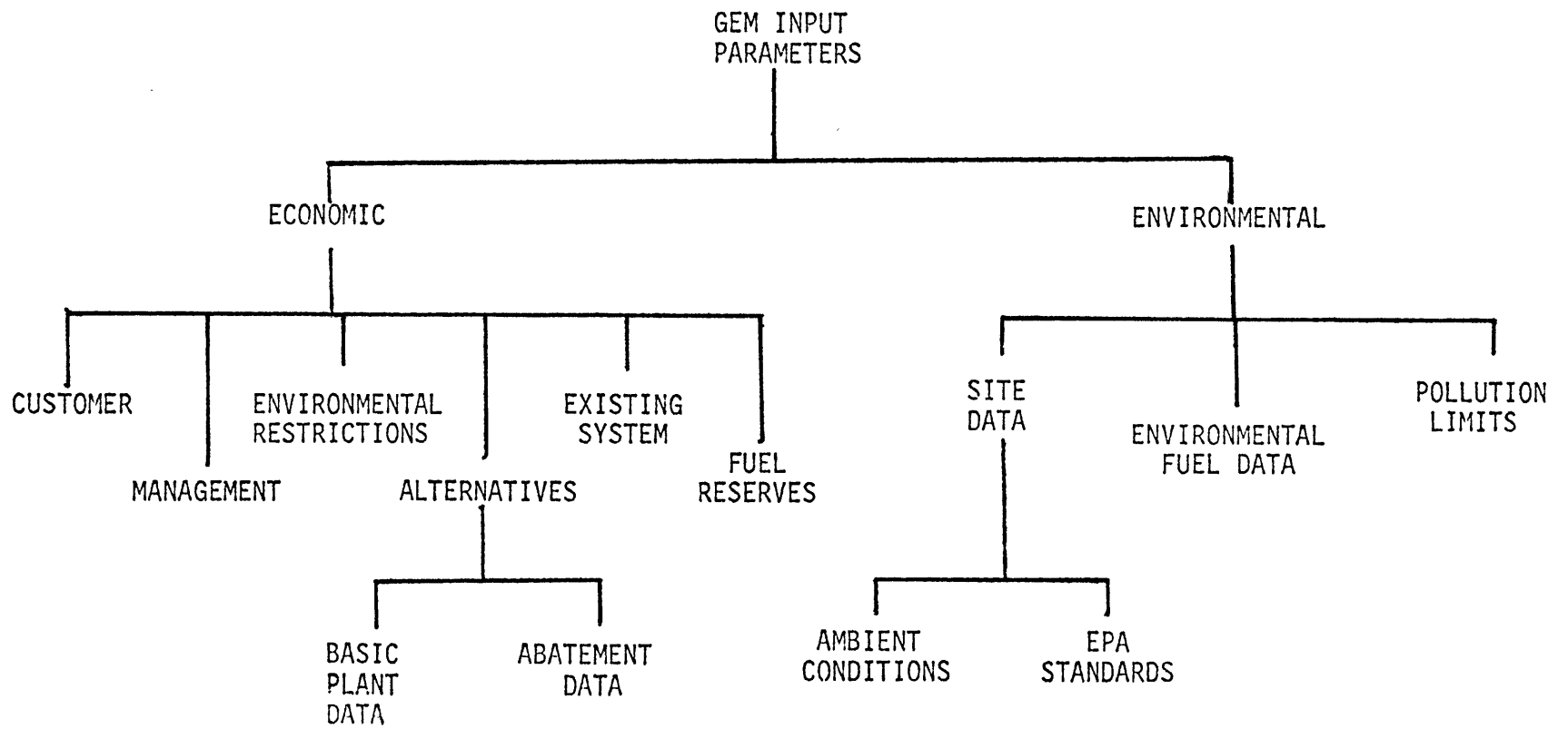
Figure 4.1.   GEM Input Parameters

Financial considerations (i.e, beyond that of standard engineering/economics) can be handled in a similar manner as can generation profiles for solar technologies and perturbations to load given schemes for load modification. Thus, in terms of scope, the EGEAS data base structure could evolve into a structure as shown in Figure 4.3.

4.3 LEVEL OF DETAIL

Figure 4.2 shows two areas boxed in by dotted lines. These represent different levels of detail which can be accessed within the environmental data base. The box showing the input into the LP is composed of data required for simple representation of environmental emissions and constraints. If full environmental screening is to be performed using dispersion models to calculate ground-level concentrations, maximum temperature rises in water plumes, etc., the more extensive site data are required. These site data are not required if the environmental screening models are not to be run.

The same type of approach will be used in structuring the EGEAS data base and its interface extensions. For example, an interconnection could be input in the form of a very reliable unit or it could be represented in much more detail as described in the section on Interconnections. The level of detail employed for a given analysis would depend on the data availability, reliability, and on the modeling constraints.

There must be consistency of assumptions between the various levels of detail (e.g., if both load duration curve and energy are supplied along with a peak load forecast then the area underneath the load curve should equal the energy). Also the trade-offs between complicated data retrieval routines and complicated data structure must be evaluated.

4.4 RELIABILITY OF DATA-MAINTAINABILITY-EASE OF MODEL USE

Another consideration in the design of the EGEAS data structure is the extent to which certain types of data can be validated. Whereas last
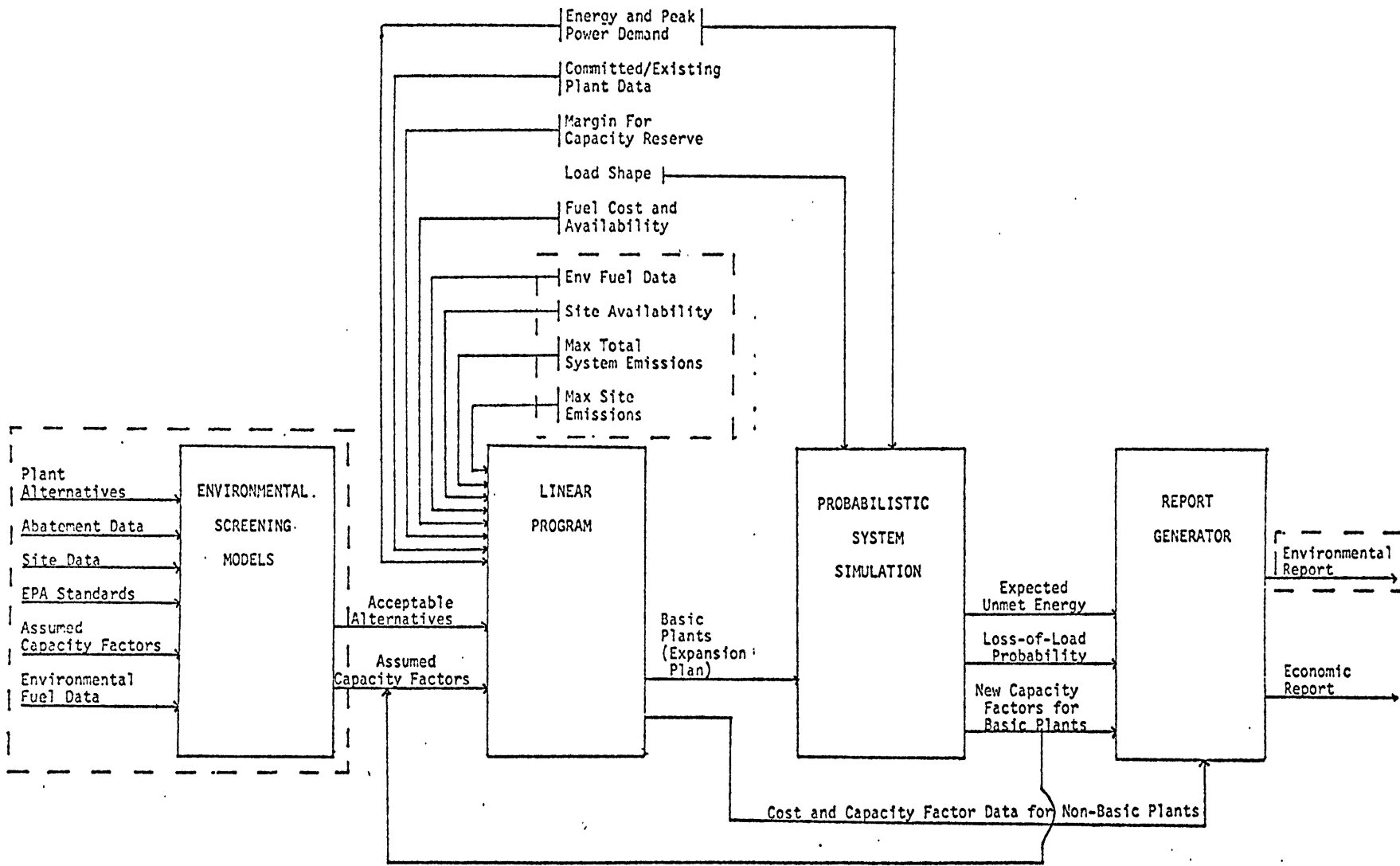
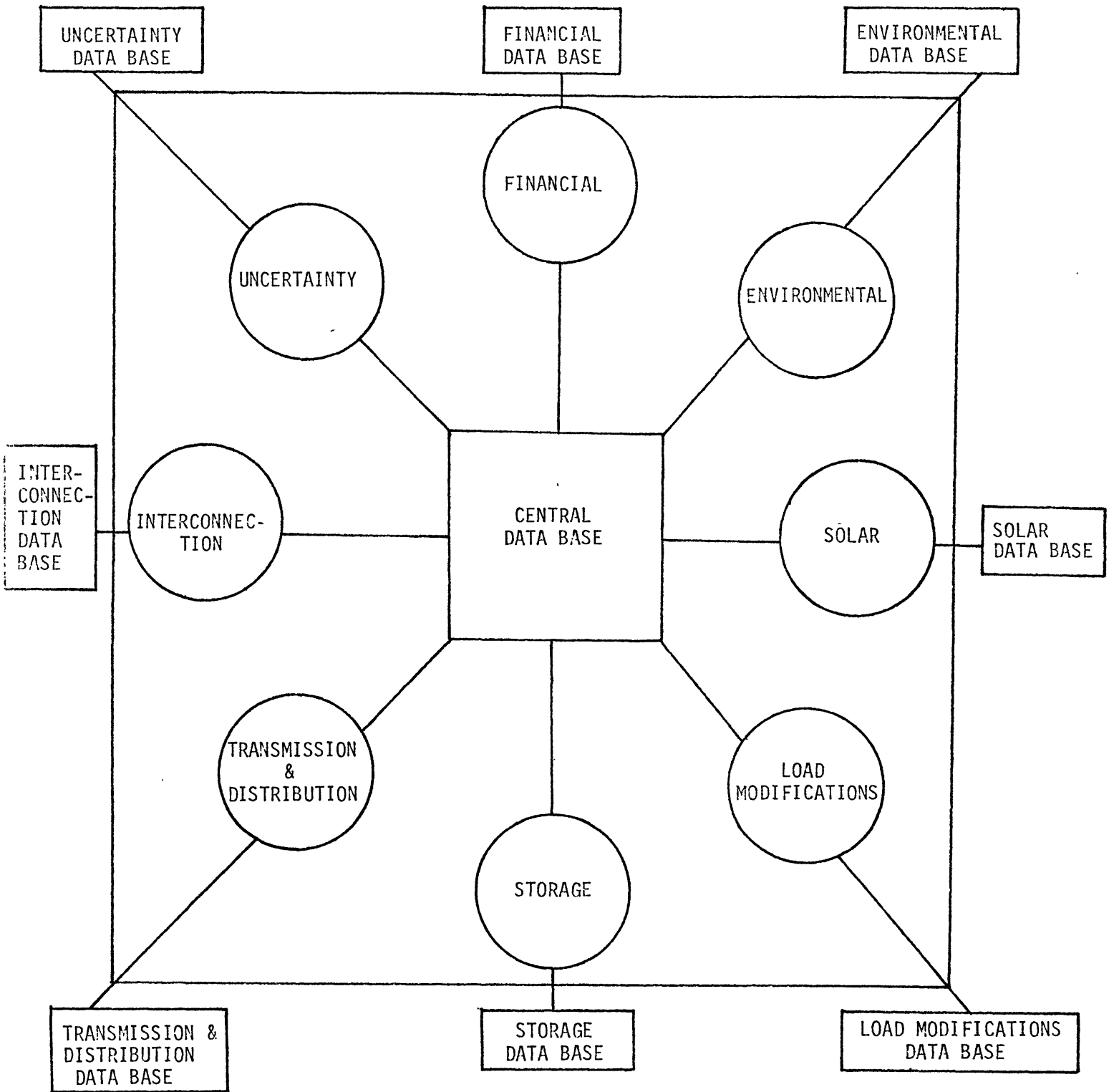Figure 4.2.   Detailed Functional Diagram of GEM

Figure 4.3. General Representation of Proposed EGEAS Data Base

year's hourly loads can be verified, the loads projected for the 20th year of a 20-year forecast are at best an educated conjecture. The EGEAS structure will attempt to categorize data as known, base projection, or study variations.

By so doing, the information on the known system can be accumulated and maintained in a data base which is different from that containing scenario data. Projections based on extensive study or which simply represent "best engineering guess" can be established and reviewed in a similar manner. These categories of the data base will be relatively stable. The study variation category is where perturbations to the known and base projection categories will be input for a particular study. Data accessing routines would automatically substitute information in the study variation data base for that in the known and the base projections data bases when such data is called for during program execution. This approach minimizes the set-up time required for a particular run, while also minimizing sources of error due to data handling.

To facilitate information retrieval, data accessing routines should be developed. These low-level routines could be called by user-written programs thus allowing special programming requirements of specific utilities to be modeled more precisely and to be interfaced more easily with components of EGEAS. The data base reporting routines would be provided to list information in the basic data base and its interface extensions as well as to create summary reports. Plotting capabilities should also be used for better data base checking, as well as for output analysis. This, however, is beyond the scope of this contract. Routines which will check the data base or internal consistency (checking cross references, and ensuring consistency between levels of detail, etc.) as well as reasonableness of data (range checking) will be provided.

4.5 SUMMARY

Considerations being studied in designing the EGEAS data bases have been presented above. Modularity has been proposed, addressing scope (interface extensions to data base), reliability of information (known,

base projection, study variation), and levels of detail. Data accessing routines are proposed to insulate programs from the data structure complexity, when needed, and to facilitate development of programs by EGEAS users to address the specific analytical needs of individual utilities. Using the above guidelines, the EGEAS data base will hopefully develop into a flexible, adaptable, easy to access/use data system for utility planners.

Section 5

OPTIMIZATION TECHNIQUES STATUS

The following is a summary description of the three optimization
techniques which will be available to the EGEAS user and a report on
their status. The optimization techniques comprising separate modules
within EGEAS are Linear Programming (GEM), dynamic programming (OPTGEN)
and an application of Generalized Benders' Decomposition. Discussion of
terminal effects treatment and a comparison of the three optimization
options follows.

5.1 LINEAR PROGRAMMING

5.1.1   Status

The MIT Generation Expansion Model (GEM) is a set of generation expansion
planning programs which can be used to analyze and select capacity
expansion plans for electric utility systems. GEM is written in FORTRAN
and has been implemented on the MIT Information Processing Center's
IBM-370/85.

GEM has undergone substantial modification and has been tested in its
modified form on utility data. Further improvements are under
development as part of the EGEAS project, including the possible
integration of financial considerations (constraints and/or objective
function modifications) into the model's structure. GEM in its present
form is scheduled to be used for preliminary test runs by the end of
January 1980, so that the actual inclusion of modifications into the
program's code are subsequently implemented. Modifications are presently
in the conceptualization stage.

5.1.2 General Description

Among capacity expansion models, GEM exhibits the following unique characteristics:

o   Expansion alternatives are characterized by a plant type, fuel type, nominal capacity, site type, thermal pollution abatement technology and air pollution abatement technology.

o   The cost and performance characteristics of air pollution controls are explicitly incorporated.

o   The feasibility of expansion alternatives may be tested by comparing performance to emission and ground level air quality standards.

o   The required minimum stack height for meeting air quality standards may be determined by an outside routine and input into the model.

o   The cost and performance of water pollution controls are explicitly incorporated.

o   The feasibility of expansion alternatives may be tested by comparing performance to water quality standards in an outside routine.

o   The required design characteristics of water quality control technologies may be determined by an outside routine and input into the model.

o   The incorporation of a site availability constraint.

The following characteristics apply to the more conventional aspects of the package:

o   Plant types can include hydro and pumped storage.

o   Incorporates both capacity and energy constraints in determining the need for new units.

o   Incorporates fuel availability constraints.

o   Utilizes separate production cost model.

GEM utilizes a linear programming algorithm to minimize investment, fuel, and operating costs over the planning period. Operating costs are represented as a linear function of the capacity of new and existing plants by means of a capacity factor supplied for each plant during each time period by an exogenous to the LP production cost model. The capacity factor is equal to total energy produced by each plant in each time period, over the length of that time period multiplied by the plant's capacity. Thus the investment decision is optimized to define an investment plan consisting of a schedule of plants to be built during the planning horizon. For each time period in the planning horizon, GEM simulates the operation of the scheduled system to determine expected energies and capacity factors. These become new assumptions for a revised investment optimization, and the iterative process continues until the investment and operating solutions converge to a consistent, minimum-cost design.

The linear program contains constraints on peak power, energy, fuel and emissions/resources. Peak power constraints force capacity addition each year together with existing capacity, to satisfy an exogenously set reserve margin. Energy constraints utilize the capacity factor supplied by the production cost model, to ensure that energy produced each year by new and existing plants net of pumped hydro losses, does not fall below expected total energy demand. Similarly fuel constraints use capacity factors to impose limits on yearly and overall consumption of each fuel. Finally, emission/resource constraints are also expressed as linear functions of existing and new plant capacities using capacity factors.

The investment plan is produced as a set of continuous decision variables representing capacities of various available expansion alternatives added each year. The production cost model simulates the system operation in each year to yield new capacity factors different from those used by the LP. The LP is solved again using the new capacity factors. Upon convergence, the primal and dual solutions and slack variables are summarized and made available to the user.

5.1.3 Technical Description

As already described above investment decisions are made by a linear programming algorithm while the capacity factors of alternative plants are determined exogenously to the linear program. Iterative updating of capacity factors is an option to the user. The capacity factor of alternative i, installed in period j, during period t is defined as:

$$ICAPFC_{ijt} = \frac{\text{Energy produced during time period (t)}}{\text{Length of time period (t) x capacity}}$$

The objective function and constraints utilized by the model are described below.

5.1.3.1 Objective Function.

The objective function for the investment decisions is the total present worth of all capital, operating and fuel costs that are incurred with the chosen generation expansion plan. The capital charges of the existing and committed system are not included since they are clearly beyond the control of the new plan. Since the investment decision uses fixed capacity factor assumption, the operating and fuel costs of the existing and committed system can also be ignored. The objective function is:

$$\text{Min } Z = \sum_{i=1}^{NALT} \sum_{j=1}^{NTP} C_{ij} * X_{ij}$$

where

NALT = number of alternatives

NTP = number of time periods

C_{ij} = the present worth at the start of the study of all capital, operating and fuel charges incurred for a plant alternative i installed in the time period j.

X_{ij} = continuous decision variable representing the number of plants of alternative i beginning operation in period j.

An "alternative" is a combination of several technologies and environmental choices, and is specified by:

1. Generation Class
2. Plant Site
3. Fuel Grade
4. Air Pollution Abatement
5. Water Pollution Abatement

Specification of generation class directly implies assumptions on technology, plant size, fuel type, costs, escalation rates, plant lifetime, forced outage rates, maintenance and seasonal deratings.

"Periods" are usually, but not necessarily, years. They must be uniform. An alternative begins operation on the first day of a period and is retired on the last day of a period.

The costs C_{ij} can be expanded into components as follows:

$$C_{ij} = \left({}_cC^b_{ij} + {}_cC^{air}_{ij} + {}_cC^{water}_{ij} \right) +$$

$$\left({}_oC^b_{ij} + {}_oC^{air}_{ij} + {}_oC^{water}_{ij} \right) + C^{ext}_{ij}$$

where

$\quad {}_cC^b_{ij}$ = present worth total of basic (b) plant capital and fixed operating costs (c) for alternative i installed in period j.

$\quad {}_cC^{air}_{ij}$ = present worth total of air pollution abatement related (air) plant capital and operating costs (c) for alternative i installed in period j.

$\quad {}_cC^{water}_{ij}$ = present worth total of water pollution abatement related (water) plant capital and operating costs (c) for alternative i installed in period j.

$\quad {}_oC^b_{ij}$ = as above but plant variable operating and fuel costs.

$\quad {}_oC^{air}_{ij}$ = as above, but plant variable operating and fuel costs.

$\quad {}_oC^{water}_{ij}$ = as above, but plant variable operating and fuel costs.

C_{ij}^{ext} = extension period cost. Can be expanded in six components similar to the above only referring to the extension period.

It is important to note that objective function costs have two components due to basic alternative costs and environmental costs. In a purely economic study GEM drops all costs except $_cC_{ij}^b$ and $_oC_{ij}^b$. The extension period costs are intended to even out distortions which may be introduced by terminal effects. Extension period costs represent the present value of an infinite stream of levelized investment costs and operating costs starting at the end of the planning period. In the present version of GEM levelized costs and operating costs during the extension period are taken to be equal to those during the unit's year of installation and the last year of the planning period respectively. Revising extension period costs so that they reflect capital and operating cost (fuel, etc.) escalations during the extension period, is investigated.

5.1.3.2 **Peak Power Constraints.** These constraints are written to guarantee that sufficient capacity is available in each period to meet the demand with an acceptable reliability. The effect of an exact reliability constraint, which is highly nonlinear, is approximated by specifying a reserve margin in period t, $M_t(0 \leq M_t)$. The peak power constraints can be expressed as:

$$\sum_{i=1}^{NALT} \sum_{j=1}^{t} CAP_i * X_{ij} - PEAK_t(1 + M_t) - \sum_{k=1}^{NCEX} CAPCEX_k \geq 0$$

where

CAP_i = peak capacity of alternative i.

$PEAK_t$ = peak load in period t.

NCEX   = number of committed and existing units.

$CAPCEX_k$ = peak k capacity of existing and committed units.

Units which have been retired before period t are not included in this constraint. In effect this constraint causes sufficient new capacity to be built in a time period to fill the gap between existing and committed capacity and the peak plus margin requirements. Note that capacity of a unit does not change with time.

5.1.3.3 <u>Energy Constraints</u>. This constraint, which ensures adequate energy is supplied to the customers, resembles the peak power constraint. Pumped hydro must be handled with care since its energy comes from other units on the system. The constraint requires that energy produced in period t minus the losses in energy storage must exceed energy demand in period t. Algebraically:

$$\sum_{i=1}^{NALT} \sum_{j=1}^{t} HOURS * ICAPFC_{ijt} * CAP_i * X_{ij} -$$

$$\sum_{i \in PS} \sum_{j=1}^{t} (1/\eta - 1) * HOURS * ICAPFC_{ijt} * X_{ij} \geq$$

$$ENERGY_t - \sum_{k=1}^{NCEX} NRGCEX_{kt}$$

where

HOURS   = hours in time periods.

$ICAPFC_{ijt}$ = capacity factor of alternative i, installed in period j during period t.

$ENERGY_t$ = energy demand in period t.

$NRGCEX_{kt}$ = energy of existing or committed unit k in period t.

η = pumped hydro efficiency.

Units which have been retired before period t are not included in this constraint. The constraint does not allow energy to be stored in one time period for use in another. It does not limit the pumped hydro energy supply to base loaded plants.

5.1.3.4 <u>Fuel Constraints</u>. These constraints limit the amount of fuel which can be consumed by the system in any period t. Fuels are constrained by grade and type. The constraints are:

$$\sum_{i=1}^{NALT} \sum_{j=1}^{t} \frac{FLHR_i}{FHC_{mn}} * HOURS * ICAPFC_{ijt} * CAP_i * X_{ij}$$

$$\leq FULMAS_{mnt} - \sum_{k=1}^{NCEX} FULCEX_{mnkt} \qquad \forall\ m,\ n$$

where

$FLHR_i$	= full load heat rate of alternative i.
FHC_{mn}	= fuel heat content for type m and grade n (associated uniquely with alternative i).
$FULMAS_{mnt}$	= fuel mass of type m and grade n available in period t.
$FULCEX_{mnkt}$	= fuel mass of type m and grade n used by committed or existing unit k in period t.

Retired units are not considered. Period fuel constraints, like the peak load and energy constraints, remove the effects of existing and committed system from the right hand side and allow the alternatives to use the remaining fuel supply. Unlike peak load and energy, a total system constraint can be applied for fuel:

$$\sum_{t=1}^{NTP} \sum_{i=1}^{NALT} \sum_{j=1}^{t} \frac{FLHR_i}{FHC_{mn}} * HOURS * ICAPFC_{ijt} * CAP_i * X_{ij}$$

$$\leq FULMAS_{mnT} - \sum_{t=1}^{NTP} \sum_{k=1}^{NCEX} FULCEX_{mnkt} \qquad \forall\ m,\ n$$

where

$FULMAS_{mnT}$	= total fuel mass available in planning horizon, type m, grade n.

5.1.3.5 Emission Resources Constraints. Constraints on the period, or system planning horizon: total SO_2, particulate or heat emissions or water or land consumption, are similar in form to the fuel constraints. For example, the amount of SO_2 emitted during any period is constrained to be less than some value. One difference is that the effect of

existing and committed units is not accounted for. The general form of
the constraint is

$$\sum_{i=1}^{NALT} \sum_{j=1}^{t} Q_{ir} * HOURS * JCAPFC_{ijt} * CAP_i * X_{ij} \le QLIMIT_{tr} \quad \forall \ r$$

where

Q_{ir} = emissions or consumption of r-th quantity (SO_2, particulates, heat, land, water) per unit energy for alternative i.

$QLIMIT_{tr}$ = maximum allowable emissions or consumption of r-th quantity in period t.

Retired units are not considered. The form of the general system
constraint is:

$$\sum_{t=1}^{NTP} \sum_{i=1}^{NALT} \sum_{j=1}^{t} Q_{ir} * HOURS * ICAPFC_{ij} * CAP_i * X_{ij} \le QLIMIT_{Tr}$$

where

$QLIMIT_{Tr}$ = maximum allowable emissions or consumption of r-th quantity during planning horizon.

5.2 DYNAMIC PROGRAMMING

5.2.1 Status

OPTGEN is a dynamic programming capacity-expansion program developed by
Stone and Webster Engineering which has been repeatedly tested on
electric utility data. Test runs in the context of the EGEAS project are
scheduled by the end of January 1980. Work is in progress to incorporate
OPTGEN in the EGEAS structure and make it compatible with the EGEAS data
base common to all modular EGEAS components. Modifications of the OPTGEN
code and/or adaptation of the EGEAS data representation and retrieval
will be implemented to that end.

5.2.2 General Description

The basic problem solved by OPTGEN is that of developing a generation
expansion plan which minimizes the present worth of the revenue
requirements subject to specified reliability and reserve constraints.
Such a plan is called optimal. There are many other plans, often
numbering in the millions, which also satisfy the constraints. Only one
is optimal, but there are many top plans which cost only slightly more.
One hundred such plans are available for output. However, with the
exception of the optimal plan, there is no guarantee that they form the
true top 100. Backward as well as forward dynamic programming procedures
are used to broaden the number of plans considered. The number of states
allowed in a given year is limited to 200 and optimality is not
guaranteed if the number of states is truncated; however, in most cases,
the best plan is still obtained.

Revenue requirements are made up of two components, the capital costs and
the production or operating costs. The capital costs are the fixed
charges and property taxes of new generating units. The operating costs
include the fuel costs of all generating units and the operating and
maintenance costs of new units. The present worths of these annual costs
are cumulated over the study period and the reference date is the first
year of the period. For comparison of different expansion plans which
may have different capacities in the last year, the capital costs of the
last year are adjusted according to a common criterion, either minimum
reserve percentage or minimum reliability index. The annual costs of the
last year can be projected for a stated period and its present worth
added to the total cost of the expansion plan. This total cost is used
as the objective function of the program, i.e., the program attempts to
minimize this total cost.

A maximum of five alternative types of generating units are allowed by
the program at any one run to develop the optimal expansion plans. Any
differentiation in capacity, energy cost, investment cost, or forced
outage rate constitutes a different type. Thus one may compare units of
the same fuel but of different sizes or one may compare units of

different types of fuel. By running different combinations and using engineering judgment, five types are generally sufficient to find the optimum mix.

The production cost method used is the loading trapezoid. This is a heuristic method wich models the effect of random forced outages, maintenance outages, and other operating peculiarities of the system on the loading of units. Even though the loading trapezoid method does not treat the forced outages rigorously, it lends itself easily to the calibration procedures to fit observed data. Committed units may be installed at any time during the expansion period and existing units may be retired at any time.

5.2.3 Technical Description

Following is a more detailed description of the objective, constraints, solution method and production costing of the existing version of OPTGEN, adapted from S. Lee et al., "Comparative Analysis of Generation Planning Models for Application to Regional Power System Planning."

5.2.3.1 Objective Function.

The objective of the program is to minimize the present worth of the annual revenue requirement over a selected period. Two periods for defining the objective function are allowed:

(1) Simulation period only, i.e., only those years in which actual load growth and unit additions are simulated.

(2) Simulation period plus an evaluation period of any duration. In the evaluation period, load growth is assumed to be stopped and generating units are replaced in kind.

Revenue requirement consists of fuel costs, O and M costs, depreciation, interest payment, insurance, taxes (if any), and return on equity. A levelized fixed charge rate is used to represent the equivalent uniform annual cost of owning a particular facility. Fixed charges include those for generating facilities as well as for site-related transmission facilities.

Escalation rates can be specified for capital investment (one rate for all types), separately for three fuel types, and for all operating costs.

Only one discount rate for present worth calculation is allowed and it cannot be time-varying.

5.2.3.2 Reserve Constraints. The reserve constraints used in the program define a minimum and a maximum percentage reserve in which feasible expansion plans are sought.

5.2.3.3 Reliability Constraint. A reliability index is calculated for each potential state of expansion and a minimum reliability index based on the benchmark year performance is used to reject unreliable expansion plans. This constraint may be nullified in which case the minimum reserve percentage becomes the binding constraint.

The calculation of the reliability index is based on a simplified and approximate method of estimating the probability of loss of load (LOLP). For the benchmark year, the cumulative probability distribution of forced outages is computed by the usual convolution process. The LOLP based on the peak load for the benchmark year is calculated. Its value is normalized to 1.0 and is the minimum required reliability index.

The cumulative distribution of forced outages is then approximated by four log-linear segments evaluated at intervals equal to the standard deviation of the distribution. The reliability index of a future state is estimated by computing the mean and standard deviation of forced outages, expressing the reserve of that year in terms of standard deviations above the mean value of forced outages, and obtaining it from the log-linear approximations of the distribution function for the benchmark year.

5.2.3.4 Maximum Number of Units. Each generation alternative can be restricted by a maximum number of units which are allowed to be installed during the entire expansion period.

5.2.3.5 <u>Solution Using Forward Dynamic Programming</u>. The basic problem of generation expansion is formulated as follows. Each year in the expansion period is a stage. In each year, there are many combinations of new units which form feasible states, e.g., in the first year there may be three states, one being one 900 MW nuclear unit, the second being one 600 MW coal-fired unit, and the third being three 100 MW gas turbines.

As the years progress, the number of states increases because more new capacity is needed, and there are many different combinations of the different types of units which can meet the requirement. This is the so-called "curse of dimensionality" because the computational requirement increases with the number of states, which increases roughly exponentially with the number of alternative types of units.

Without some heuristic scheme of truncating the number of states, it is impractical to solve a problem with more than three alternative types. The heuristic truncation method which allows four or even five alternatives to be run simultaneously will be described later.

Figure 5.A shows an example with two types of alternatives, a 400 MW fossil unit and a 54 MW gas turbine, and a four-year expansion period, not counting the benchmark year which is denoted by the left-most circle with two zeros. In the first year, the program finds two states which result in reserves between the specified minimum and maximum and satisfy the reliability index. They are (0,4) and (1,0), indicating four gas turbines and one fossil unit, respectively.

For each state, the program simulates the production cost of the system and finds the state among all states in the previous year which, when proceeding to the present state, does not necessitate a deletion of a unit, and which results in a minimum cost incurred up to the present year. For the first year, the only feasible transition is from (0,0) and the minimum cost is just the cost incurred in the first year. This so-called <u>cost-to-date</u> is the total operating and production costs and the fixed charges, present-valued and cumulated up to and including the
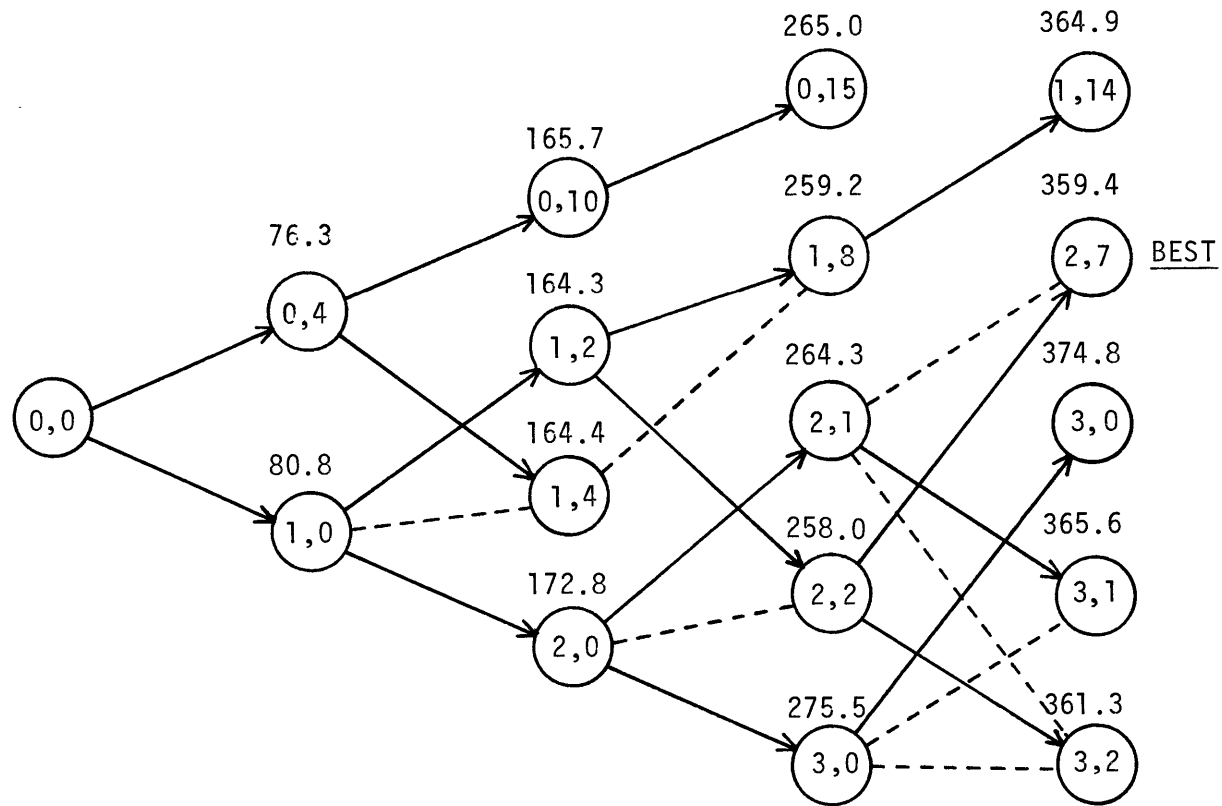
Figure 5.A. Generation Expansion by Dynamic Programming
Notation for New Units Installed

x,y x = Number of 400 MW Fossil Units
     y = Number of 54 MW Gas Turbines

5-14

present year. Thus the state (0,4) requires a minimum of 76.3 million dollars to reach it from the beginning.

The program then proceeds to the second year and finds four feasible states, (0,10), (1,2), (1,4) and (2,0). It simulates the production costs and for each state, it looks back one year and from the two previous states it determines which of them can proceed feasibly to the present state. For instance, (1,4) can come from both (0,4) and (1,0). Among these feasible prior states, the program computes the additional costs for the present and adds them respectively to the minimum costs of the prior feasible states. From these costs-to-date, it selects the minimum cost-to-date and remembers the transition from the prior state which yields the minimum. This is called the backward pointer. For example, (1,4) has a minimum cost-to-date of $164.4 million and the backward pointer is shown as an arrow coming from (0,4). The dotted line from (1,0) shows the other feasible transition.

The program proceeds in like fashion to the last year. At this point, the minimum cost-to-date for each state in the last year is calculated and then sorted to determine the minimum cost for all feasible transitions. In the example, (2,7) is the best state in the last year and the minimum cost is $359.4 million. To find the expansion schedule, it is only necessary to retrace the backward pointers. Thus the optimal plan is the following sequence of states: (0,0) - (1,0) - (1,2) - (2,2) - (2,7). Subtracting one state from the following state gives the unit added each year. The optimal installation schedule thus determined is listed below.

Year	Units Added 400 MW	54 MW
1	1	0
2	0	2
3	1	0
4	0	5

5.2.3.6 <u>Derivation of 100 Best Plans</u>. If the objective is to find the optimal plant only, forward dynamic programming is sufficient. A plan can be traced backward from each of the terminal states with the backward pointers or solid arrows in Figure 4. This does not give too many suboptimal plans. Backward dynamic programming is used to increase the number of such plans.

In backward dynamic programming, the algorithm starts from the next-to-last year. For each state, it finds the feasible transitions to the following year and determines the transition which results in the minimum cost-to-go. The forward pointer indicates the cheapest forward transition from that state. The program then sweeps backward and repeats for all years until it reaches the beginning. In essence, it is the same as forward dynamic programming except for the reversal of direction.

Since the screening process of determining whether a state satisfies the reserve and reliability criteria and the production costing have already been done in the forward algorithm, this part takes much less time. When both methods are combined as in this program, the number of suboptimal plans which are available is limited only by the storage requirement.

Many of these plans may be identical for most of the years and are simply minor variations in the last two or three years. In order to obtain the significant suboptimal plans in the output, a number equal to the number of years in the end of the period for which minor variations may be ignored, can be specified. For each group of plans which are identical up to the specified end years, the program will print only the cheapest plan. In this way, the top 100 plans will include a lot more plans with significant variations.

5.2.3.7 <u>Production Decisions</u>. Two methods of production costing are available: probabilistic and deterministic. This probabilistic method is similar to that in WASP. For computation efficiency, the deterministic method is usually used.

The deterministic method uses a trapezoidal approximation of the annual
plant duration curve. The trapezoid's vertical height equals the system
generation capacity, its width equals 8,760 hours (a year) times the
maximum capacity factor of the base load units, and its area equals the
energy demand (MWhr) for that year. The energy generated by the
individual units is approximated by horizontal strips of the trapezoid if
the vertical axis is subdivided according to the rated capacities of the
units arranged in order of their energy cost with the inexpensive base
load units at the bottom and the peaking units on top. The resulting
capacity factors fit the actual data better than the conventional method
of stacking units on the load duration curve, because all units including
peaking units are loaded to various degrees.

It should be pointed out that this is a heuristic method which attempts
to model the effect of random forced outages, maintenance outages and
other operating peculiarities of the system on the loading of units.

The accuracy can be further improved by two calibration factors. A
peaking constant which is used to increase or decrease the rated capacity
of peaking units in the formation of the trapezoid can be adjusted to
change the loading of peaking units. Similarly, a cycling constant is
specified to change the loading of cycling units.

The individual loading of all units can be fine-tuned by the use of
individual maintenance factors, which derate the units in the loading
triangle. The relation of the derated capacity of a unit used in the
loading trapezoid to the maintenance factors is detailed in the following
equation.

$$\text{Derated Capacity} = \text{Rated Capacity} \times (1 - \frac{\text{Maintenance Factor}}{\text{Base Value}})$$

In this fashion, the loading of a unit can be adjusted by varying the
maintenance factor.

After the capacity factor of a unit is determined by the loading
triangle, the energy cost is calculated by a reciprocal curve shown in

Figure 5B. H_{max} and H_0 are specified for each unit. H_{max} is the heat rate at maximum loading multiplied by the fuel cost. H_0 can be adjusted to obtain the correct energy cost for lower capacity factor.

5.2.3.8 <u>Truncation of Non-Optimal States</u>. The theory of state truncation is based on the assumption that the optimal plan is fairly close to being of minimum cost-to-date in each year up to the last year. This is especially true if the cost-to-date for each state is adjusted to account for the differences in the installed capacity, e.g., a state representing the addition of a big nuclear unit may have excess capacity for that year resulting in a high cost-to-date, which when prorated by the minimum required capacity, may actually be less than the adjusted cost-to-date of a state with small units. The criterion for determining the minimum required capacity is either minimum percentage of reserve or fixed LOLP index.

The method of state truncation is to eliminate states in years when the number of states exceeds a specified number by first determining the minimum adjusted cost-to-date in the previous year. States in the previous year which have adjusted costs above a certain ratio to the minimum are then flagged. States in the present year whose backward pointers indicate a transition from a flagged state are then eliminated. If the resulting number of states in the present year still exceeds the maximum, the cost ratio is reduced by a factor more than once if necessary, and the elimination process repeated.

5.2.3.9 <u>Adjustment for End Effects</u>. Since different expansion plans may have different system capacities in the last year of the study period, it is not correct to compare their revenue requirements without some adjustment to account for the end effects. The reserve and reliability constraints are used to adjust the capacities in the last year to an equal basis, either minimum reserve percentage or fixed LOLP index. The fixed charges in the last year associated with the units newly installed in that year are prorated according to the adjustment in capacity. In other words, it is assumed that only portions of these units are installed in the last year.
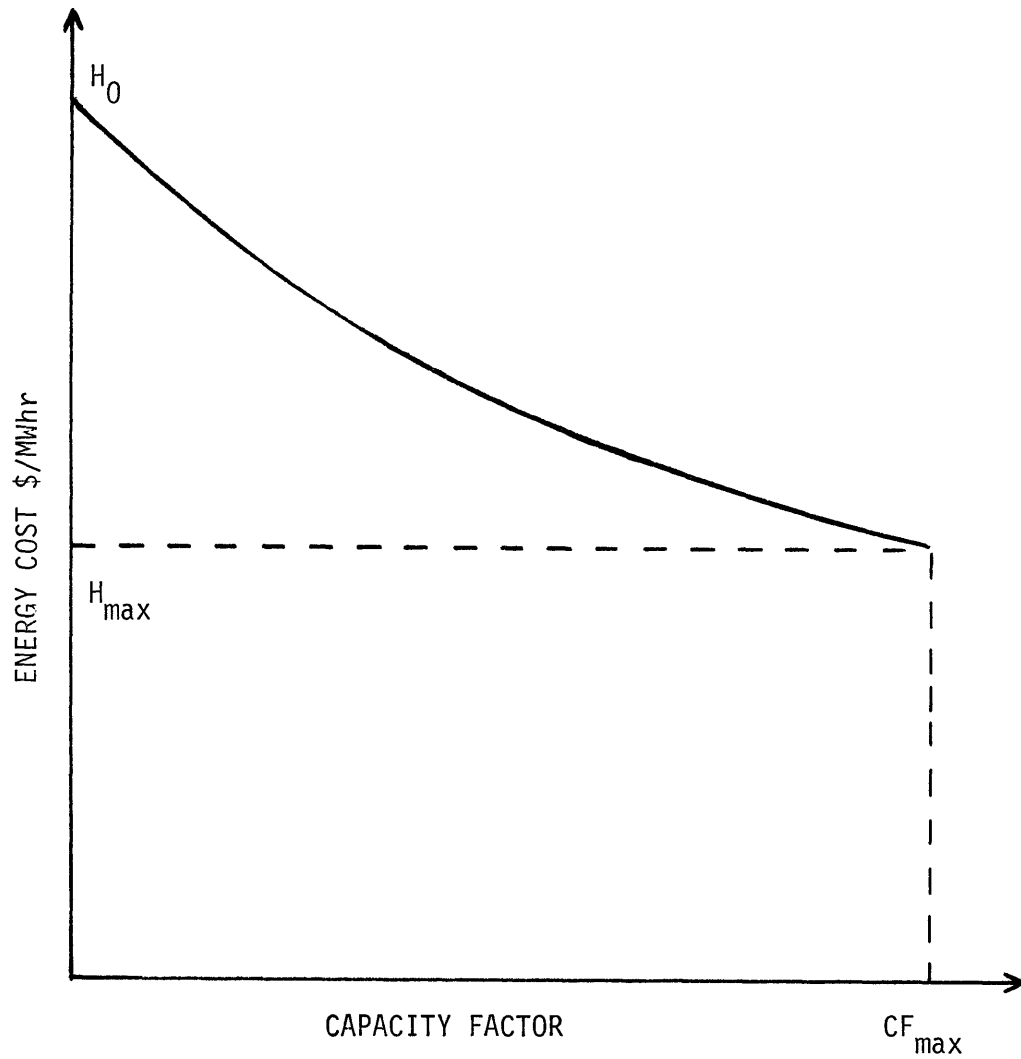
Figure 5B. Energy Cost vs. Unit Capacity Factor

Furthermore, the adjused cost of the last year can be projected for any number of years and the present worth revenue requirements for this evaluation period is added to the objective function for minimization.

5.3 GENERALIZED BENDERS' DECOMPOSITION

5.3.1 Status

An algorithm utilizing Generalized Benders' Decompositon was developed at MIT by J. Bloom. A preliminary, basic version of the algorithm has been coded and is available on the MIT computer system. Work is well under way on both improving the logic of the algorithm (particularly as regards the incorporation of the reliability constraints in terms of unserved energy) and extending its scope to deal with
- hydro units
- pumped hydro
- cogeneration
- new energy technologies (solar, wind)
- load modification.

While substantial progress has already been made in properly incorprating the unserved energy reliability constraint and handling hydro units, work concerning the other items is still in the conceptualization stage. Test runs of the code and derivation of preliminary computation results are scheduled by the end of January 1980. Further development of the algorithm and the code will continue throughout the first months of 1980.

5.3.2 General Description

The problem considered by the Generalized Benders' algorithm is the determination of a minimum-cost capacity expansion plan which meets forecasted loads over a 20-30 year horizon. Cost in this problem consists of two components, the initial capital cost of building the generating plans which can be expressed as a linear relationship of added capacity, and the continuing cost of operating the generating system to meet the demand of customers which can only be expressed as a complex

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nonlinear relationship of available capacity. In addition, because of random load fluctuations and random plant outages, to ensure that customer demand is met with the desired reliability, a standard of service defined in terms of a probabilistic measure of expected unserved energy is imposed. This reliability constraint can again be represented only as a complex nonlinear relationship of available capacity.

The above complex nonlinear program is broken into two parts, the determination of optimal investments in new generating capacity (master problem) and the determination of the operating cost and reliability of the generating system (subproblems). It is then solved using generalized Benders' decomposition, a mathematical programming technique summarized below.

The subproblems are used to determine the minimum cost of operation and the reliability of a trial system (initially specified by the user, then supplied by the master problem) in each period of the planning horizon. Though it has the form of a difficult nonlinear optimization, the subproblem is solved, without resorting to nonlinear programming, by using a standard production costing technique, the probabilistic simulation of Baleriaux and Booth. Associated with the solution of the subproblem is a set of Lagrange multipliers which measure the changes in system operating cost (λ) and reliability (μ) caused by marginal changes in the trial plant capacities. These multipliers are then input to the master problem to provide a first order Taylor expansion linear representation of the nonlinear operating cost component of total cost (the objective function in the master problem) and the nonlinear reliability constraint. Using this linear approximation of operating cost and reliability around the trial solution, the master problem provides a new trial solution. The subproblem is then used to provide the master problem with an additional linear approximation around the new trial solution. As iterations between the master and subproblem proceed, the number of constraints addressed by the master problem increase providing an ever-improving piecewise linear representation of operating cost and system reliability, until convergence is obtained. At any

iteration the current piecewise representation of the system cost
provides a lower and an upper bound on the optimal cost. Hence, provided
that the current trial solution is feasible, the algorithm can be
terminated if desired prior to optimality with known error bounds. A
graphic representation of the master problem-subproblem interaction may
be found in Figures 5.1 and 5.2 that follow.

5.3.3 Technical Description

Following is a mathematical description of the general long-range
planning problem and the way it is handled by an application of
Generalized Bender's algorithm. The application is formulated and the
computation of variables by means of which the master and subproblems of
the decomposition communicate is also described.

5.3.3.1 Formulation of the Long-Range Planning Problem. The long-range
planning problem for a system of thermal generating plants can be stated
as follows:

$$\underset{\underline{X},\underline{Y}_1,\ldots,\underline{Y}_T}{\text{minimize}} \quad Z = \underline{C}'X + \sum_{t=1}^{T} EF_t(\underline{Y}_t) \tag{1}$$

$$\text{subject to } EG_t(\underline{Y}_t) \leq \epsilon_t \qquad t = 1,\ldots,T, \tag{2}$$

$$0 \leq \underline{Y}_t \leq \delta_t \underline{X} \qquad t = 1,\ldots,T, \tag{3}$$

where

$\underline{X}$ = vector of unit capacities, X_j MW (decision variable),

j = unique index for each unit,

$\underline{C}$ = vector of unit present-value capacity costs, C_j \$/MW
(note C_j = 0 if j is an existing unit and X_j is fixed),

$\underline{Y}_t$ = vector of unit utilization levels in period t, Y^{it} MW
(decision variable),

i = loading order position of unit in period t,

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Capacity of plant type i X_i

A

x_i^1

μ_i^3 (μ_i^3, μ_j^3)

B

x_i^3 μ_j^3

E

C

Isoreliability Contour

x_i^2

D

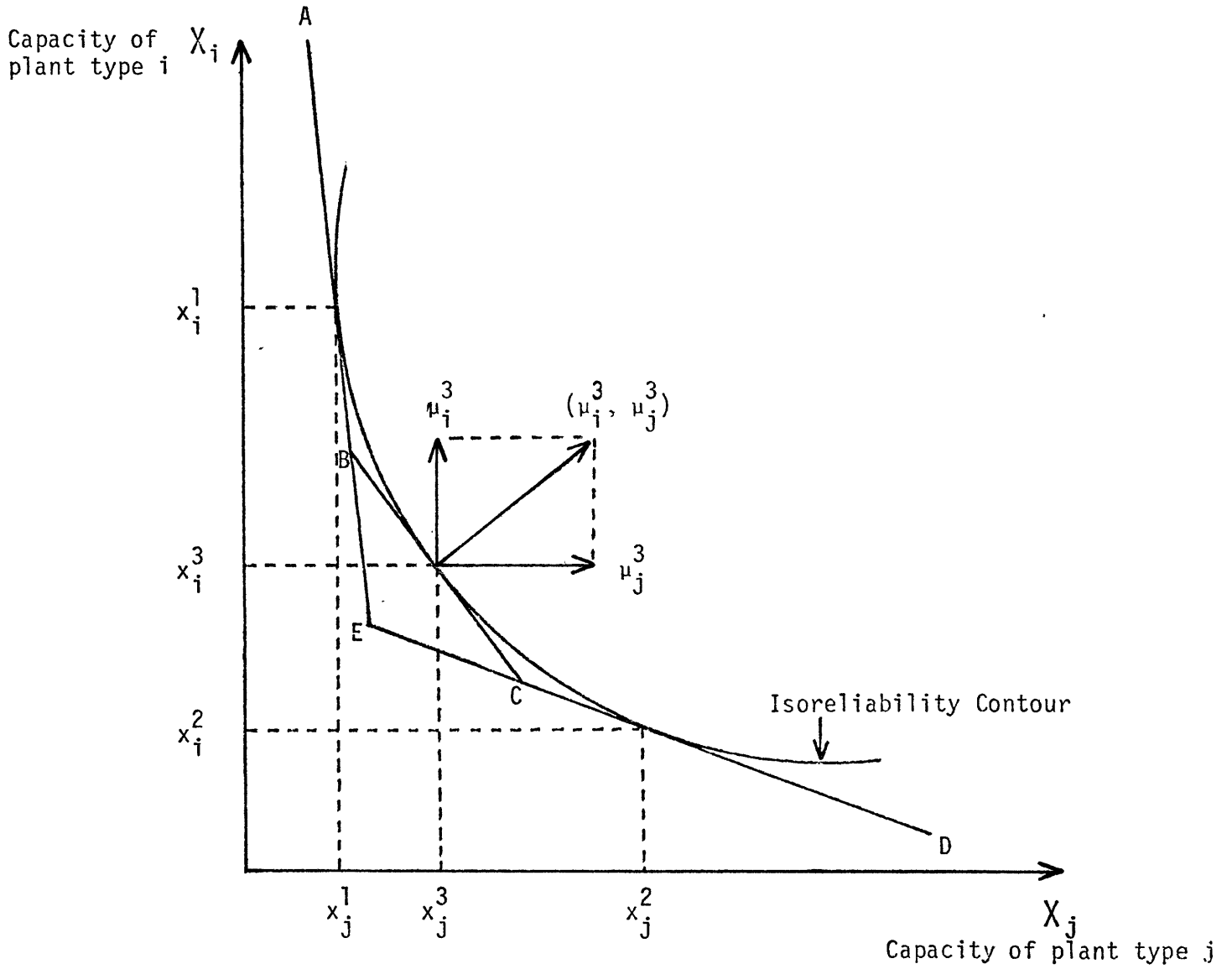x_j^1 x_j^3 x_j^2

X_j
Capacity of plant type j

Figure 5.1. Improvement of piece-wise linear representation of isoreliability contours with additional iteration. μ_i^k, μ_j^k, provided by subproblem, x_i^k, x_j^k by master.

Note: Superscripts refer to iteration number. Successive improvement of piece-wise linear representation of isoreliability contour. After two iterations AED, while after three iterations ABCD.
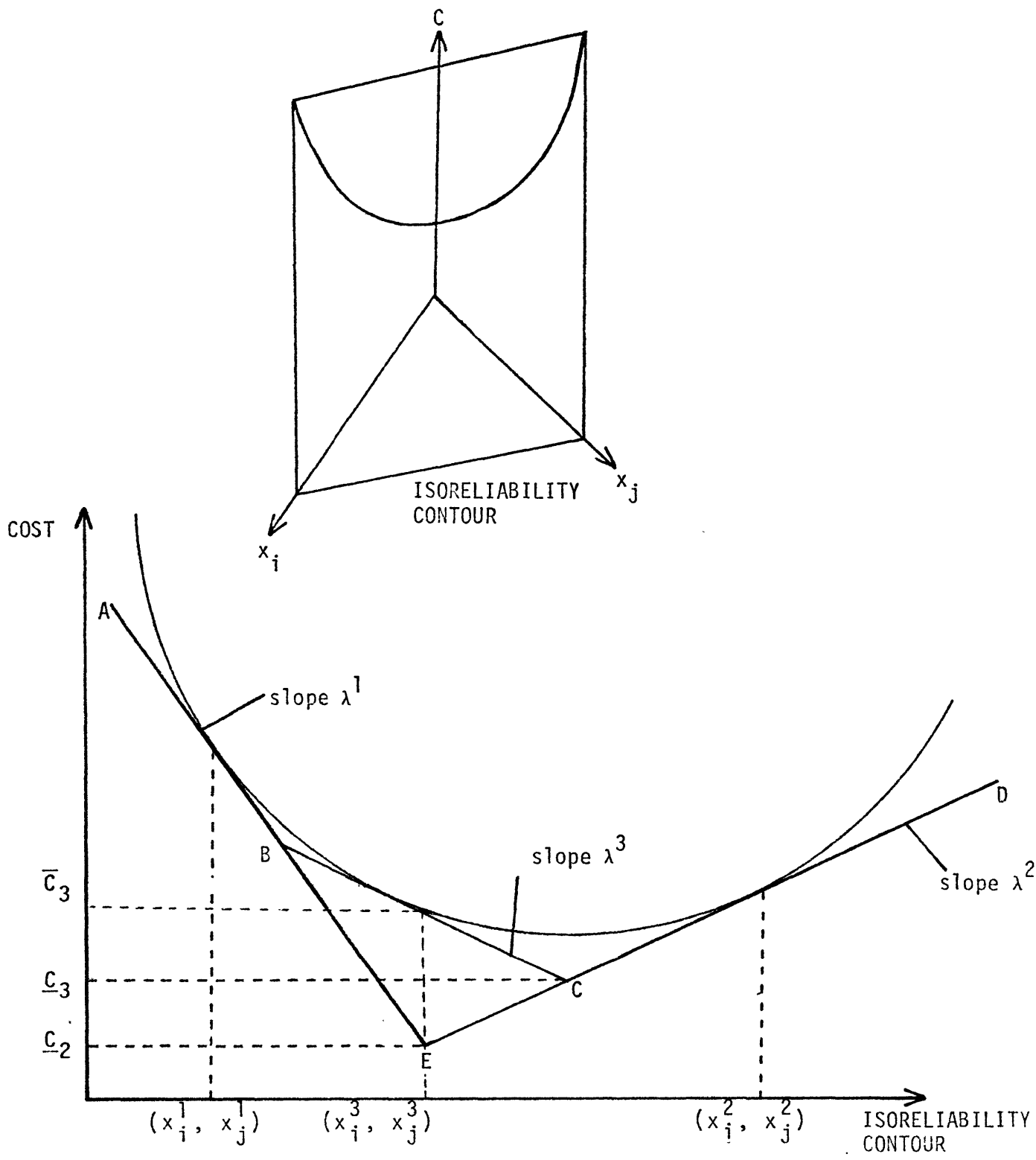
Figure 5.2. Improvement of piece-wise linear representation of operating costs for a constant reliability level.

Note: A linear isoreliability contour is used to simplify graphic representation. Piece-wise representation of cost: After two iterations AED. After three iterations ABCD. $\underline{C}_2$ lower bound after 2nd iteration. $\underline{C}_3$ lower bound after 3rd iteration. $\overline{C}_3$ upper bound after 3rd iteration.

$EF_t(\underline{Y}_t)$ = present value expected operating cost function in period t,

$EG_t(\underline{Y}_t)$ = expected unserved energy function in period t,

ϵ_t = desired reliability level in period t, measured in expected MWh of demand not served,

δ_t = matrix which selects and sorts units, indexed by j, into economic loading order, induced by i, in period t, and

T = number of periods in planning horizon.

In this formulation, the expected unserved energy is used as the reliability measure. Recent discussion has suggested that this measure more realistically represents the loss to customers than the more commonly used loss of load probability. The expected unserved energy weights the probability of each loss of load state by the size of the shortage in that state.

The expected operating cost and unserved energy are determined in the production costing model, which can be stated as follows:

$$\underset{Y^1,\ldots,Y^I}{\text{minimize}} \quad EF(\underline{Y}) = \sum_{i=1}^{I} F^i p_i \int_{U^{i-1}}^{U^i} G_i(L)dL \tag{4}$$

$$\text{subject to } EG(\underline{Y}) = \int_{U^I}^{\infty} G_{I+1}(L)dL \leq \epsilon \tag{5}$$

$$0 \leq \underline{Y}^i \leq X^i, \tag{6}$$

where

i = index of unit in loading order,

I = number of units in loading order,

Y^i = utilization level of i-th unit, MW (decision variable) (component of vector $\underline{Y}$)

X^i = capacity of i-th unit MW (regarded as fixed in the operating problem),

F^i = operating cost of i-th unit, \$/MWh,

p_i = $1-q_i$ = availability of i-th unit,

q_i = forced outage rate of i-th unit,

G_i = equivalent load duration curve faced by i-th unit, and

$$U^i = \text{cumulative utilization of first } i \text{ units in loading order}$$
$$(U^{i-1} \text{ is the loading point of the } i\text{-th unit}).$$

The unit loading points are determined by the equations

$$U^i - U^{i-1} = Y^i, \quad i = 1, \ldots, I, \tag{7}$$
$$U^0 = 0.$$

The equivalent load duration curves are determined by the recursive relationship of probabilistic simulation

$$G_{i+1}(L) = p_i G_i(L) + q_i G_i(L - Y^i) \quad i = 1, \ldots, I \tag{8}$$

where $G_1(L)$ is the system load duration curve, the expected time in hours per period during which the load exceeds the level L. Thus, the equivalent load duration curve $G_i(L)$ gives the expected time during which the load plus the capacity on outage of the units below i in the loading order exceeds level L. Equation (8) is just a special case of the more general convolution equation

$$G_i(L) = \int_0^{U^{i-1}} G_1(L - x) h_i(x) dx$$

where $h_i(x)$ is the unit outage distribution. $h_i(x)$ = probability of an outage of size x among the first i-1 units in the loading order.

There is a production costing problem of the form (4)-(6) for each period t in the planning horizon. The index t has been dropped above for clarity of notation; however, the unit operating cost F^i, availabilities p_i, utilization levels Y^i, and the loading order i itself as well as the system load duration curve G_i all depend on the time period t.

The use of the utilization levels Y^i is, in a sense, an artifact of the model, since it implies that plants that would cause the system to exceed the reliability standard are not operated. However, in the

optimal solution, capacity in excess of that required to meet the reliability standard is usually not built.

5.3.3.2 Solution of the Long-Range Planning Model by Generalized Bender's Decomposition.

The algorithm proposed for solving the long-range planning problem (1)-(3) is generalized Benders' decomposition. As described in the introduction, this algorithm divides the problem into a master problem, which replaces the nonlinear problem (1)-(3) with a linear program, and a set of production costing subproblems of the form (4)-(6). The master problem is solved to generate a set of trial unit capacities ($\underline{X}$); its structure will be considered in detail below. Consider first the subproblems, which are solved to determine the expected operating cost and reliability of the trial system.

The optimal solution to the operating problem (4)-(6) is straightforward. The loading order is defined as the economic merit order in which the units are loaded in order of increasing operating costs. Hence, the indices i are defined so that

$$F^1 \leq F^2 \leq \ldots \leq F^I.$$

The the optimal solution is to set

$$Y^i = X^i$$

in merit order $i = 1, 2\ldots$, until the reliability constraint (5) is satisfied. The last unit used, n, will generally not be used to capacity. Thus, n is defined so that

$$\int_{U^{n-1}+Y^n}^{\infty} G_{n+1}(L)dL = \varepsilon$$

for Y^n such that $0 < Y^n \leq X^n$, and

$$Y^i = \begin{cases} X^i, & i < n \\ 0, & i > n. \end{cases} \tag{9}$$

It will sometimes happen that the capacities X^i will be insufficient to meet the reliability constraint (5), in which case $n = I$,

$$Y^i = X^i \text{ for all } i = 1,\ldots,T,$$

and

$$\int_{U^I}^{\infty} G_{I+1}(L)dL > \epsilon$$

In this case, the production costing problem is infeasible.

Associated with the solution of this problem are Lagrange multipliers, which measure the value of small changes in the capacities X^i . Let λ^i be the Lagrange multiplier associated with the i-th capacity constraint (6) and π be the multiplier associated with the reliability constraint (5). Then these multipliers must satisfy the Kuhn-Tucker conditions

$$\lambda^i + \pi \frac{\partial EG}{\partial Y^i} = -\frac{\partial EF}{\partial Y^i}, \quad i = 1,\ldots,n-1$$

$$\lambda^i = 0, \qquad\qquad i = n,\ldots,I \tag{10}$$

$$\pi = F^n,$$

where the derivatives are evaluated at the optimal solution Y^i. Formulas for computing these multipliers are given in the next section.

If the operating problem is infeasible, then it is necessary to compute Lagrange multipliers which measure the change in reliability caused by small changes in the capacities. These multipliers μ^i must satsify

$$\mu^i = -\frac{\partial EG}{\partial Y^i}, \qquad i = 1,\ldots,I \tag{11}$$

Formulas for computing these multipliers are also given in the next section.

The Lagrange multipliers are used to build the master problem, which has the following form

$$\text{minimize } Z \atop Z,\underline{X} \tag{12}$$

subject to

$$Z \geq \underline{C}'\underline{X} + \sum_{t=1}^{T} [EF_t^k + \underline{\lambda}_t^k \delta_t(\underline{X}^k - \underline{X})], \quad k = 1,\dots,K, \tag{13}$$

$$\sum_{t \epsilon \Gamma_k} EG_t^k + \underline{\mu}_t^k \delta_t(\underline{X}^k - \underline{X}) \leq \sum_{t \epsilon \Gamma_k} \epsilon_t, \quad k = 1,\dots,K, \tag{14}$$

where

   k = index of trial solutions

   K = number of trial solutions generated so far,

   X^k = vector of unit capacities of k-th trial solution,

   $\underline{X}$ = unit capacities of current trial solution to be determined (decision variable)

   Z = total cost of current trial solution (decision variable),

   EF_t^k = expected operating cost of k-th trial solution in period t,

   $\underline{\lambda}_t^k$ = vector of Lagrange multipliers associated with k-th trial solution in period t,

   EG_t^k = expected unserved energy of k-th trial solution in period t,

   Γ_k = set of period t in which k-th trial solution is infeasible,

   $\underline{\mu}_t^k$ = vector of multipliers associated with infeasible subproblems in period t for trial solution k.

The data EF_t^k, $\underline{\lambda}_t^k$, EG_t^k, Γ_k, and $\underline{\mu}_t^k$, are generated by solving the subproblem for period t with the k-th trial unit capacities $\underline{X}^k$.

The master problem (12)-(14) is actually a linear approximation to the long-range capacity planning problem (1)-(3). The constraint (13) can be regarded as a linear approximation to the objective function (1) evaluated about the trial solution $\underline{X}^k$, with the multiplers $\underline{\lambda}_t^k$ representing the derivatives of the operating cost function at that trial solution. Similarly the constraint (14) can be regarded as a linear approximation to the reliability constraint (2) evaluated at the k-th trial solution with the multiplers $\underline{\mu}_t^k$ representing its derivatives at that point.

As each new trial solution is generated, new constraints of forms (13) and (14) are added to the master problem. Thus the master problem increases in size as the algorithm proceeds. As long as the trial solution is infeasible or it violates the new constraints it generates, it is not the optimal solution. However, when a trial solution is found which is feasible and which satisfies the new cost constraint (13) it generates, it is the optimal solution to the problem. At any iteration, the value of Z is a lower bound on the optimal cost, and if the trial solution found is feasible, then the value of right-hand side of the cost constraint (13) it generates is an upper bound on the optimal cost. Hence, the algorithm can be terminated prior to optimality with known error bounds.

5.3.3.3 <u>Computation of the Lagrange Multiplers</u>. The Lagrange multipliers are computed for the optimal solution to the operating subproblem, which is given by (9).

In the case that the subproblem is feasible, the Lagrange multipliers are given by the Kuhn-Tucker conditons

$$
\lambda^i = \begin{cases} -F^n \dfrac{\partial EG}{\partial Y^i} - \dfrac{\partial EF}{\partial Y^i}, & i < n, \\[2ex] 0 & , \ i \geq n. \end{cases}
$$

In the case that the subproblem is infeasible the multipliers are defined by

$$\mu^i = - \frac{\partial EG}{\partial Y^i}, \quad i = 1, \ldots, I.$$

Define the function $H_{ij}(U) = \frac{\partial}{\partial Y^j} \int_0^U G_i(L)dL$, where U stands for any U^i with $i \geq j$. Then

$$H_{ij}(U) = 0 \text{ for } i \leq j,$$

and

$$H_{i+1,j}(U) = \begin{cases} p_j G_j(U) & , \ i = j. \\ p_i H_{ij}(U) + q_i H_{ij}(U-Y^i) & , \ i = j+1, \ldots, I. \end{cases}$$

Then

$$\frac{\partial EF}{\partial Y^j} = \Delta_j p_j G_i(U^j) + \sum_{i=J+1}^{n} \Delta_i p_i H_{ij}(U^i) +$$

$$(\sum_{i=n+1}^{I} \Delta_i p_i) H_{n+1,j}(U^n), \ j \leq n,$$

and

$$\frac{\partial EG}{\partial Y^j} = - H_{I+1,j}(U^I),$$

where

$$\Delta_{j-1} = F^{j-1} - F^j + q_j \Delta_j, \quad j = I, \ldots, 2,$$

$$\Delta_I = F^I.$$

The coefficient Δ_j is the expected difference in operating cost between

plant j and the next available plant in the loading order, which can be seen by expanding its definition

$$\Delta_j = F_j - p_{j+1}F^{j+1} - q_{j+1}p_{j+2}F^{j+2} - \cdots - q_{j+1}q_{j+2} \cdots q_{I+1}p_I F^I.$$

Then, finally

$$\lambda^j = \begin{cases} -\Delta_j p_j G_j(U^j) - \sum_{i=j+1}^{n} \Delta_i p_i H_{ij}(U^i) + \Delta_n H_{n+1,j}(U^n), & j < n, \\ \\ 0 & , & j \geq n, \end{cases}$$

and

$$\mu^j = H_{I+1,j}(U^I).$$

In actual computation, the functions $H_{ij}(U)$ can be more efficiently determined by the recursion

$$H_{ij}(u) = \begin{cases} G_i(U) - \dfrac{q_j}{p_j} H_{ij}(U - Y^j), & U > Y^i, \\ \\ p_j S & , & U \leq Y^j, \end{cases}$$

where $S = G_1(o)$ = number of hours per period.

5.4 ANALYSIS OF TERMINAL EFFECTS

The need for handling terminal effects arises because of the finiteness of planning horizons in utility expansion planning models. The costs and benefits associated with plants continue to accrue in the years beyond the plan period. These and related factors constitute the terminal effects which should be taken into account in the search for an optimal expansion plan.

Most terminal effects can be grouped and analyzed under one of the following categories:

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1) Issues that relate to the treatment of capital that is unused at the end of the planning horizon

2) Issues concerning shifts in the relative economics of plants caused by differential rates of inflation for the cost components of various types of plants, changing system characteristics due to non-steady state conditions of relative prices, emergence of new technologies, etc.

5.4.1 The Valuation of Unused Capital

Standard, well-established practices exist for the valuation of unused capital. The two main methods for dealing with this are outlined below.

1) A salvage value can be assigned to the capital stock which continues to generate benefits, along with associated costs, beyond the plan period. This salvage value can be determined in a variety of ways. The amount of undepreciated capital can be used as one indicator of the salvage value. It could also be evaluated by prorating the capital investment over the plant life on the basis of expected yearly energy generation. This approach is generally adopted in dynamic programming models, where the condition of discrete plant size leads to excess capacity in the last year of the plan period.

Once determined, the total salvage value of all the units installed during the plan period is subtracted from the total capital investment and this reduced capital base is used for minimizing the cost of expansion. Reference 1 presents a sophisticated formulation of the salvage value technique based on the dual equilibrium approach. This method has been shown to lead to significant reductions in the required length of the planning period while retaining the accuracy of the optimization results.

2) The stock represented by the total capital investment on a plant can be converted into a series of yearly flows by applying a levelized fixed charge rate. These uniform yearly flows are charged off

during the life of the plant, which may extend beyond the plan period, and thus the problem of unused capital at the end of the planning horizon is cicrumvented.

5.4.2 Shifts in Economics After Planning Period

In contrast, there is no standard, widely accepted technique for dealing with the disequilibrium issues arising from differential inflation rates and non-steady-state behavior of relative prices. A consideration of total costs beyond the planning horizon could well lead to an expansion plan different from the one indicated by an analysis of plan period costs only. This could be caused by such circumstances as steeper escalation of fuel costs associated with particular plant types, costs introduced by regulation, etc., in the years after the plan horizon.

5.4.3 Replacement

Another related issue is the replacement of plants when they are retired after the plan period. The two-way linkage between decisions made during and after this period makes it necessary to develop a terminal effects model that can simulate replacement also.

5.4.4 Approaches for Handling Time-Dimension

The time-dimension underlying terminal effects can be modeled in two ways:

1) A long planning horizon can be specified so that terminal effects become relatively insignificant when discounted to the present. The length of the plan period could typically be chosen to be twice or thrice the operating life of the longest-lived plant in the system.

Within such a framework, either of the following options can be adopted:

i)   All the time-periods during the plan horizon can be assumed to be of the same length and detailed cost computations can be done for all these periods.

ii)   The time-periods could be increased in finite steps so that a more aggregated analysis can be done for later years.

2) Extension Period Approach. An extension period, which follows the planning horizon, can be introduced as an artifice to capture terminal effects. Escalation rates, costs of new plants at the point of replacement and such other parameters could be projected and specified as inputs for the extension period. Detailed production costing and similar extensive analyses would not be made for the extension period, but cost-related computations would be done by projecting at pre-specified escalation rates the costs of the last plan year.

The structure and sophistication of a model using an extension period would depend on trade-offs among the following factors:

a)   The quality of decisions during the extension period—a number of options exist, ranging from a treatment similar to plan period optimization to prespecified decision rules.

b)   The length of the extension period—this could be finite or infinite

c)   Computational time and cost

d)   Model complexity

5.4.5   Treatment of Terminal Effects in Some Existing Models

A. GEM: The levelized cost approach is adopted in GEM to handle capital stocks. An infinite extension perod is used during which the total costs as of the last year of the planning horizon are assumed to continue. The levelized fixed charges and operating costs associated with a unit that is being retired are assumed to hold for the plant that replaces it. The total of present-worthed planning and extension period costs is used for optimization.

B. OPTGEN: Levelizing and a finite extension period are used in OPTGEN. Excess capacity in the last year of the study period, resulting from the discrete plant size condition required for dynamic programming, is prorated on the basis of reserve or reliability constraints. The fixed charges associated with plants installed in the last year are also prorated according to the adjustment in capacity. In practice, end effects which affect the selection of units in the last years of the plan period are minimized by specifying a longer plan horizon than is actually desired.

5.4.6 Terminal Effects Model Proposed for EGEAS

The main features of the terminal effects model proposed for development for EGEAS are outlined below:

1) Capital stocks will be converted into flows by using levelized fixed charges.

2) An extension period will be used for capturing terminal effects.

3) Fuel and other operating costs will be escalated during the extension period also.

4) The levelized fixed charges will be escalated when a plant is replaced.

5) The level of detail and aggregation of data would be lower during the extension period, to realistically reflect a lower accuracy associated with increasing remoteness in time period.

6) Data would be so specified as to minimize the effect of plan horizon length on the decision results and model output during the planning horizon.

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5.5 EGEAS OPTIMIZATION OPTIONS: A COMPARISON

As can be deduced from the above presentation of the three optimization techniques, there is some overlap but more often than not a unique treatment in modeling various aspects of the capacity expansion problem (namely, production cost reliability, environmental, actual unit size, etc.) and in output capabilities (number of alternative solutions, investment in non-expansion alternatives, etc.). Further, differences and similarities in data requirements and computational time requirements should also be noted.

An account is given below of some key similarities and differences among the available optimization options, and some preliminary recommendations are offered as regards the type of analyses which could be performed best by the various options. Figures 5.3 and 5.4 summarize this section.

5.5.1 Modeling Capabilities

- Production Costing/Reliability
    The Generalized Benders' option includes the most extensive modeling of the production costing/reliability aspect of the capacity expansion problem. It utilizes a probabilistic simulation production costing submodel which can adequately treat storage and limited energy units as well as new energy technologies and system reliability in terms of expected unserved energy. The DP option exhibits a less detailed production costing modeling capability, but

OPTION \ MODELING/ OUTPUT CAPABILITY	DISPATCH METHOD	NUMBER OF EXPANSION ALTERNATIVES	STORAGE HANDLING	DISCRETE UNIT SIZES	% MIX	ENVIRON- MENTAL	TIME DEPENDENT TECHNOLOGIES
DP	GOOD	5	FAIR	YES			
LP	POOR	10+	FAIR		YES	YES	
G. BENDERS	EXCELLENT	10+	GOOD		YES		YES

Figure 5.3. Optimization Options: Comparison

ANALYSIS / OPTION	INDIV. UTIL.	POWER POOL	NUMBER OF NEAR OPT. SOLUTIONS	DISCRETE UNIT SIZES	TIME DEPENDENT TECHNOLOGIES	FINANCIAL CONSIDERATIONS	ENVIRON- MENTAL CONSIDER- ATIONS
DP	PREFERRED		100	PREFERRED		GOOD	
LP		PREFERRED	1			GOOD	PREFERRED
G. BENDERS		PREFERRED	5+		PREFERRED	GOOD	

Figure 5.4 Optimization Options: Comparison

still treats capacity factors endogenously, while the LP option requires exogenously determined capacity factors.

- Number of Expansion Alternatives

    The number of expansion alternatives which can be simultaneously analyzed by the DP option may not exceed five. The other two options, and certainly the LP option, may analyze a considerably larger number of expansion alternatives without excessive computational requirements.

- Storage

    The modeling of storage is fair in the DP and LP options while the Generalized Benders' option treats storage adequately in the context of a detailed load duration curve type probabilistic simulation production cost subproblem.

- Actual Unit Size

    Investment decisions in the LP and Generalized Benders' options are represented in terms of continuous variables. Despite the fact that actual unit sizes may be reflected in system reliability calculations in the Benders option, optimal investment schedules in both options usually contain fractions of actual plants, thus making the optimal solution realizable, in a strict sense, only if shared plants purchases are possible. In contrast, the DP option models investment decisions in terms of discrete (integer) variables, thus making the study of actual unit sizes possible.

- Non Expansion Alternatives

    While given levels of effort in renewable and expansion alternatives may be represented in the LP and DP options through load modification, the actual choice of optimal levels of effort in renewable and non-expansion alternatives is only possible in the Generalized Benders' option.

- Financial Considerations

    While financial considerations may be analyzed in all three options,
    modeling the actual interaction of financial constraints and optimal
    capacity expansion choices, is possible only in the LP option.

- Environmental

    Environmental/resource constraints are adequately analyzed in the LP
    option.

5.5.2 Types of Analyses

- Individual Utility

    Many individual utilities have been traditionally resorting to shared
    plant ownership in order to benefit both from economies of scale and
    lack of excess capacity. Hence, a fraction of a plant is a real
    investment decision, and the continuous variable representation of
    capacity expansion choices in the LP and Generalized Benders' options
    is appropriate.

- Power Pool

    Capacity expansion analysis at the power pool level or for a large
    individual utility that does not enter into joint plant ownership,
    requires actual plant sizes reflected in optimal expansion choices.
    Hence the DP option could be appropriately used to either define the
    actual plant sizes to be added or to define a continuous variable
    expansion plan obtained from either the LP or the Generalized
    Benders' options, by analyzing actual plant size tradeoffs among a
    few alternatives.

- Sensitivity Analysis

    Often planners wish to analyze a good spread of near optimal
    solutions by further evaluating them by means of post processors,
    with respect to financial, regulatory, uncertainty, and other
    considerations external to the optimization logic. The DP logic
    would lend itself for this analysis without the need for multiple
    runs. On the other hand, it is often also desired to perform

sensitivity analysis on the optimal expansion path by widely varying inputs like fuel and capital costs, lead times, environmental and regulatory constraints, new technology availabilities, etc. In this case where the broad behavioral characteristics of the optimal path as a function of wide input variations is to be analyzed, a less detailed but computationally efficient option like the LP option may prove advantageous.

- Actual Plant Sizes

Whenever the actual plant capacity expansion choices may not represent shared plant ownership, the planner is interested in optimal plans in terms of discrete unit sizes, a capability available only with the DP otpimization option. The DP option will also be prefereable for analyses which focus on trade-offs between actual plant sizes in terms of cost versus reliability or excess capacity versus economies of scale and insurance against inflation. However, it should be noted that system reliability calculations in the Generalized Benders' option may reflect actual plant sizes, or actual numbers of units chosen of a particular capacity expansion alternative.

- Time Dependent Generation Alternatives

A complete analysis of new energy technologies (solar, wind, etc.) and load management requires detailed representation of the production costing/reliability outputs of the general capacity expansion problem. Among the available options, the Generalized Benders' optimization technique meets the above requirement and would hence be the preferred option for analyses which focus on time dependent generation/non-expansion alternatives.

- Financial, Environmental

Financial analysis will be possible with all optimization options as outlined in a subsequent chapter. However, environmental constraints analysis could be peformed best with the LP option.

Section 6

FINANCIAL AND REGULATORY INTEGRATION

EGEAS is designed to find cost-minimizing capacity expansion plans, where
cost is taken to be the discounted present value of all expenditures.
For some utility planning purposes it will be useful to consider also the
financial implications of different expansion plans. For example, if
some plans lead a utility to violate financial constraints in its bond
indentures, they are not feasible.

To the extent that financial and regulatory considerations are included
in the model, they may change the model output away from "minimum present
value" expansion plans. All of the approaches presented here will allow
the user to determine the magnitude of these effects, by running the
model with and without the Financial/Regulatory option. For example, if
the model is constrained to grow revenues according to a specified
pattern, the impact of this constraint on total costs and on choice of
equipment types can be determined. The financial health of a utility
depends ultimately on the prices its regulators allow it to charge.
Therefore a financial model should also model regulatory behavior,
whether implicitly or explicitly. Unfortunately the behavior of
regulators is not completely predictable. Therefore all of the options
discussed below will allow users to specify their own assumptions about
what cost pass-throughs and other rate changes will be allowed. These
assumptions will then be reflected in the revenue consequences of
alternate expansion plans.

Several options have been identified for encompassing financial and
regulatory considerations in the capacity expansion planning process.
These options reflect variations in treatment due to the characteristics
and requirements of the diverse optimization techniques offered in the

6-1

EGEAS system as well as differences in the level of integration of financial and regulatory factors into the optimization algorithm. As must be expected, the alternatives involve various trade-offs between the accuracy with which complex Financial/Regulatory interactions are captured and the difficulty and cost of obtaining such accuracy.

6.1 DYNAMIC PROGRAMMING OPTIONS

There are two major alternatives for integrating regulatory and financial conditions with the dynamic programming optimization process. The first of these involves no changes to the dynamic programming process itself, but provides for detailed ex post analysis and/or screening of the optimal and near optimal expansion plans generated by the DP. This would be accomplished through the use of a post-processor which would assess the candidate plans output by the DP on the basis of financial and regulatory considerations, and provide sophisticated financial analysis to reporting of plans surviving the screening process.

The post-processor approach takes advantage of the fact that the DP model (OPTGEN) in the EGEAS system provides information on 100 plans which meet reserve requirements and which are ranked by the DP algorithm on the basis of cost. This multiple plan feature of the DP allows meaningful consideration of Financial/Regulatory concern outside the optimization algorithm entirely. While not assuring identification of a global optimum this method will provide near optimum plans which are feasible with respect to Financial/Regulatory requirements.

In addition, post-processing would permit Financial/Regulatory analysis at any desired level of sophistication due to the fact that the processor would need to be applied to a relatively small number of candidate plans. The algorithm could, for example, simply eliminate candidate plans on the basis of considerations such as interest coverage, quality of earnings, internal to external financing, etc. On the other hand, the post-processor could go beyond elimination of infeasible plans and, in a manner similar to EPRI's Over and Under Model, adjust costs upon the basis of Financial/Regulatory factors thus possibly altering the ranking

6-2

of the various plans.* Financial reports provided by the model in the form of balance sheets, income and funds flow statements can also be at various desired levels of detail.

The post-processor would be based upon a utility pro-forma accounting model. This model would use return and investment assumptions and utility accounting conventions to simulate the financial performance of candidate plans as shown in Figure 6.1. The financial reports generated for each plan could then be tested against various Financial/Regulatory criteria to eliminate infeasible plans or to make cost adjustments as noted above.

The advantage of the post-processor approach is obvious. It provides a relatively simple method of effectively incorporating Financial/ Regulatory concerns. No modification of the DP coding would be necessary. The processor itself could incorporate any desired level of detail and sophistication, and because the model is accounting-based it might be adapted from existing commercial software.

The second dynamic programming option is to embed physically the financial and regulatory considerations as constraints within the program. Currently the number of plant types that can be evaluated in the DP is quite modest, and is limited by the number of feasible states and paths that result. Thus, additional constraints within the DP which reduce the number of feasible states and paths would increase the number of plant types that could be evaluated using the DP.

Practically, there are a number of difficulties with this approach. First, the data requirements and the dimensions of the problem increase dramatically. While the current dynamic program requires only a fixed financial charge for each plant type, embedding financial constraints would require more data items per plant type (cash flows, interest

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*The Over and Under Model adjusts annual revenue requirements to reflect higher equity returns and interest charges resulting from financial distress as reflected in interest coverage ratios.

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                  ┌─────────────────┐
                  │   Input Data    │
                  └─────────────────┘
                           │
                           ▼
           ┌──►  ┌─────────────────┐
           │     │ Start Year Loop │
           │     └─────────────────┘
           │              │
           │              ▼
           │     ┌─────────────────┐
           │     │ Calculate AFDC, │
           │     │ CWIP, Rate-base │
           │     │ Additions       │
           │     └─────────────────┘
           │              │
           │              ▼
           │     ┌──────────────────────┐
           │     │ Calculate Financing  │
           │     │ Needs                │
           │     │ --Financing Costs    │
           │     └──────────────────────┘
           │              │
           │              ▼
           │     ┌──────────────────────┐        ┌──────────────┐
           │     │ Calculate Required   │───────►│ Assumed      │
           │     │ Revenues, Income     │        │ Regulatory   │
           │     │ Statement            │        │ Behavior     │
           │     └──────────────────────┘        └──────────────┘
           │              │                             │
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           │     ┌──────────────────────┐               │
           │     │ Update Balance Sheet │               │
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           │     ┌──────────────────────┐◄──────────────┘
           │     │ Calculate Funds Flow │
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           │              │
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           └─────│ Calculate Sum-       │
                 │ mary Statistics      │
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                 │ Report Writer        │
                 └──────────────────────┘
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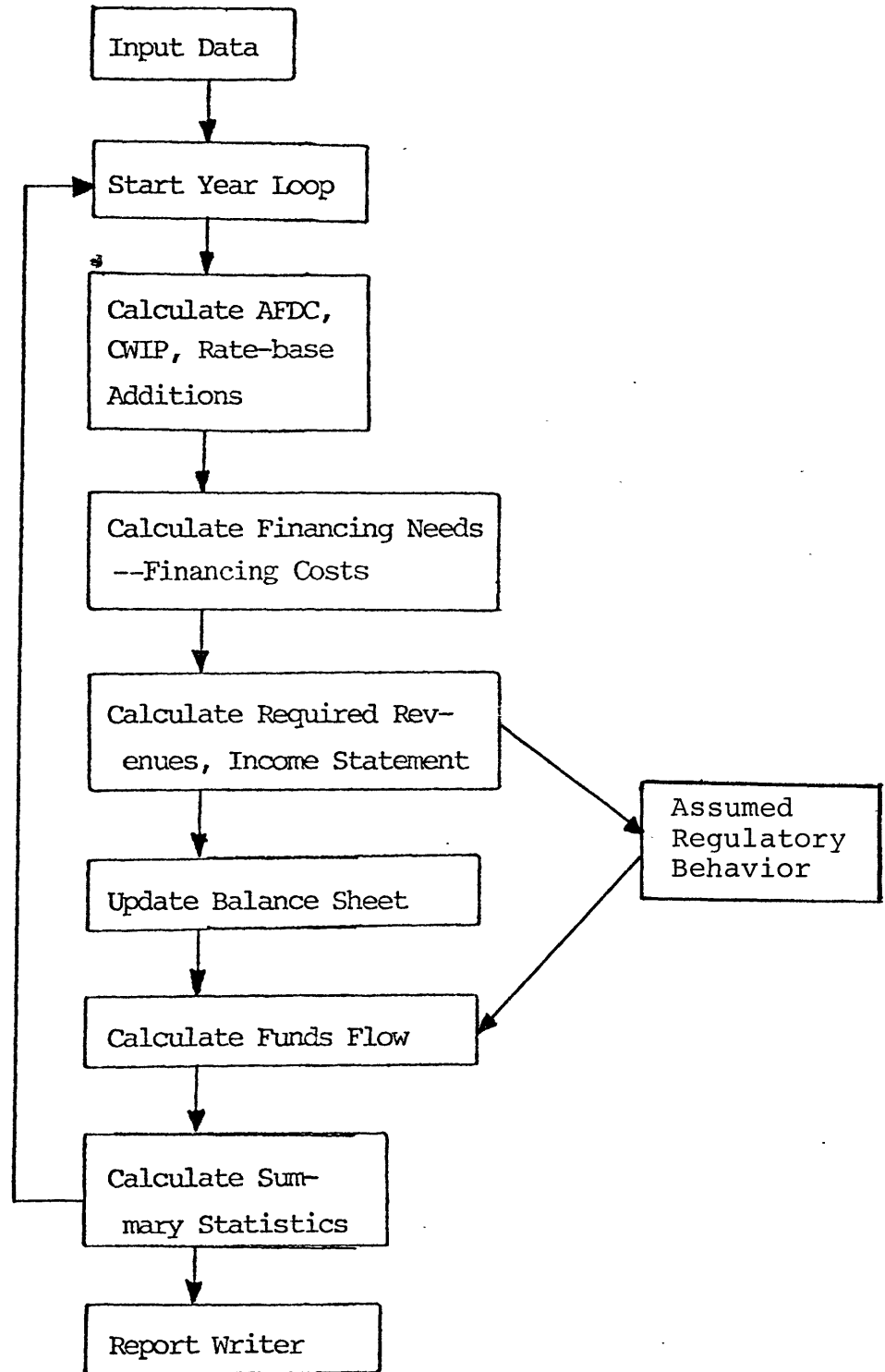
Figure 6.1. Financial/Regulatory Post Processor

coverage), the maintenance of these data over time, and the maintenance of these data by <u>path</u> rather than by <u>state</u>.

Data and dimensionality problems aside, the programming algorithm itself would require modification. Currently, the DP maintains only the preferred path to each state. With financial constraints it is possible that the preferred path might become infeasible, while the other path (feasible, but not optimal) is no longer maintained. Hence, the algorithm would have to be modified to avoid the exclusion of feasible paths. In addition, the backward DP algorithm would require modification. As currently specified, this algorithm could generate resource plans which are infeasible, as there is no check for <u>path</u> feasibility.

Finally, even if these problems could be overcome, the payoff is quite uncertain. Financial constraints are <u>path</u>-oriented. Hence. it is possible that the financial constraints would not significantly reduce the number of feasible states, and thus make little or no contribution to the capabilities of the dynamic program. While this option will be further investigated, it does not appear to be promising. Most financial and regulatory considerations can be more easily incorporated through the use of a post-processor for screening, financial analysis, and financial reporting.

6.2 LINEAR PROGRAMMING OPTIONS

Again, there are two major alternatives for integrating Financial/ Regulatory considerations with linear programming optimization. Ex post screening as described for the DP option is not helpful in the context of an LP and, therefore, does not provide a realistic alternative. If the post-processor indicates the optimal plan is financially infeasible, there is nothing to be done. The LP generates only the optimal solution, and cannot be rationally modified to generate a solution which is financially infeasible, unless financial and regulatory considerations are built into the LP.

The first reasonable option, then, is to incorporate Financial/Regulatory considerations into the LP as constraints only, leaving the objective function unchanged. Constraints could reflect a broad range of Financial/Regulatory concerns and requirements including the following:

o   Interest coverage
o   Cash/non-cash earnings
o   Internal/external financing
o   Growth of required revenues; and
o   Electricity price increases.

Such constraints, while not encompassing all of the Financial/Regulatory concerns of interest to the planner, nevertheless would assure that the LP's selection of an optimum would take into account fairly precise and realistic standards of financial and regulatory feasibility.

Because of the temporal nature of Financial/Regulatory factors, their inclusion in the LP requires development of annual financial data. These data would be generated for each plant type by a pre-processor reflecting utility accounting conventions, investment and return assumptions. From the annual profiles, coefticients representing annual revenue requirements and other financial measures (cash earnings, interest expense, etc.) would be developed and carried into the LP. The pre-processor would be utility accounting based and like the post-processor in the DP case, might be adapted from available software. However, because of the pre-processor's application to single plant types and the need to interface with the LP matrix generator, the development of a special purpose code may be more effective than attempting to correct available financial models.

This option offers the capability to constrain selection of an expansion plan in such a way as to reflect real world Financial/Regulatory concerns of interest to the planner while requiring a reasonable amount of effort. It cannot, however, capture certain complex financial impacts that may result from selection of plans which, while not violating financial constraints, nevertheless tax the financial resources or health of the utility company.

The second method for incorporating Financial/Regulatory factors into the LP is to include these factors in the objective function as well as characterizing them as constraints. This would allow consideration of alterations in capital structure, changes in the riskiness of the resource plan and financial health of the company as mentioned above. Because this is a complex task, the increase in modeling accuracy over the previous alternative would require substantial effort.

Two approaches might be taken to incorporating Financial/Regulatory impacts into the objective function. First an increased/decreased cost factor (or set of factors) could be added to the objective function. This would require development of a linear function or set of functions to relate Financial/Regulatory factors to cost increases or decreases. Since these factors interact in a complex and likely non-linear fashion, over time the development of reliable linear approximations could prove very difficult. A second approach to the incorporation of Financial/Regulatory considerations might focus upon altering the cost coefficients in the objective function to reflect the financial impacts of the selection of a particular plan. This would probably require some iterative process between the LP and a separate financial model. This of course would not only require alteration of the LP coding but would no doubt also substantially increase computation time.

Either of these methods of treating Financial/Regulatory impacts in the objective function would require substantially more effort than would be necessary for a constraints only approach. At the same time it is not clear that this increased effort would substantially improve the effectiveness of the LP as a planning tool. This is particularly true if the LP is to be used primarily as a screening device to identify candidate plans for further study.

Section 7

LOAD MODIFICATION AND RENEWABLE TECHNOLOGIES

Traditional generation expansion optimization methodologies use the
assumption that plants have constant generation availability. That is to
say, whenever the capacity is needed during the load period it can be
turned on with a given reliability. Such an assumption does not apply
for solar or wind electric power generators. The capacity available from
the solar plants is a function of time of day, time of year, weather, and
actual plant locations. Production cost capabilities have recently been
developed at Stone and Webster and at MIT in which hour by hour analysis
of solar units yields a net equivalent load duration curve on the thermal
units in such a way that the stochastic nature of the solar generation
sources is accounted for.

The decision variables in the Generalized Benders' Decomposition approach
can be anything for which Lagrange multipliers can be calculated with
regard to system revenue requirements and system expected unserved
energy. An algorithm has been designed but not yet implemented which
calculates these multipiers for expansion alternatives that cause
incremental changes in load shape which are not the result of generation
with constant availability over the load period. This is called the load
modification algorithm. One proposed handling of solar within EGEAS is
simply to find changes in load shape due to solar using a procedure
similar to that in Figure 7.1 and then to calculate the multipliers
associated with these changes in accordance with the load modification
algorithm. The multipliers can then be input directly into the master
problem in the Generalized Benders' formulation. Another approach is to
compute numerically the change in system operating cost and reliability
with respect to an incremental change in solar or other unconventional
expansion alternatives. Thus numerical estimates of the Lagrange
multipliers associated with those alternatives are obtained and interface
with the master problem is possible (see Section 5.3 of this report).

Notes to Figure Figure 7.1. Production Cost/Reliability Module for Systems With Solar Generating Sources

Basic Assumptions

1. The variable operating expense for each Renewable Resource Generation Technology (RRGT) will be less than that of any conventional units.

2. There is no predetermined dispatch order for RRGT's except that they will all be operated before any conventional units are operated.

3. Storage associated with a particular RRGT will be dedicated to that particular plant (i.e., cannot be used like a pumped hydro plant which can be charged by any plant on the system).

4. The expected operating cost of a conventional unit (A) is a function of the native customer demand, and of the capacities and forced outage rates (probabilities of outage) of units which will be loaded onto the system before (A).

Description of Modules

WTP: Weather Tape Preprocessor
WTP accepts weather tapes in TDF-14 format from the National Climatic Center (Asheville, N.C.), or in Hourly Insolation Climatology Data Base format from the Aerospace Corporation (El Segundo, Cal.), and performs the following functions:
1 - Converts all data to metric units (MKS)
2 - Adjusts data to account for differences between Solar Time and Local Standard Time at the Weather Station
3 - Creates an hourly database to be used in ROSPAM.

ROSPAM: Run Of the Sun Power Availability Module
For each type of Renewable Resource Generating Technology, on each site in each month of a year, ROSPAM outputs a discrete random variable for power available for generation or storage as a function of time of day and weather condition. Full unit forced outage rates are ignored in this Module (see LAM).

LAM: Load Adjustment Module
LAM calculates the net equivalent load curve that will be seen by the conventional units in the utility system. It does this by optimizing the operation of the Renewable Resource Generators (storage allocation) and by accounting for the mechanical forced Outage Rates of these units in a probabilistic manner. LAM also determines the operating cost of the Renewable Resource units.

SYSGEN: Electric Utility System Generation
SYSGEN calculates the production cost for each conventional unit in a utility system and the total system reliability, based on the net equivalent load curve calculated by LAM.

PWRR: Present Worth of Revenue Requirements
PWRR finds the present worth of revenue requirements for the utility, based on the producton costs calculated in LAM and SYSGEN, investment costs and financial data supplied by the utility.
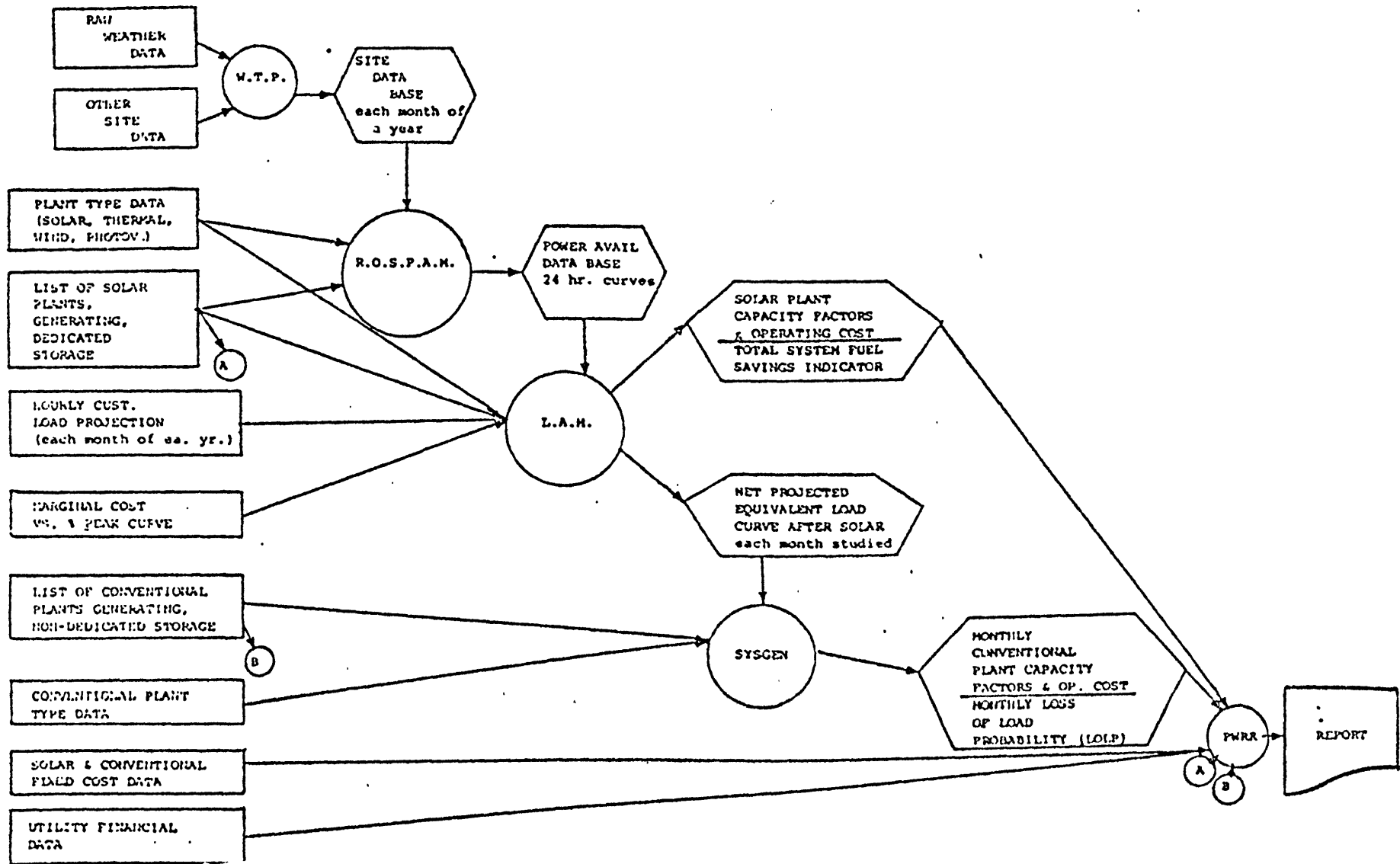
7-2

Figure 7.1. Production Cost/Reliability Module for Systems With Solar Generating Sources

It should be emphasized that solar capabilities as shown in Figure 7.1, regarding production costs and reliability analysis will be available in EGEAS for prespecified pathway analysis regardless of the feasibility of including such technique into the Generalized Benders' formulation.

Using the methodology described above, load modification techniques which involve an initial cost and some low operating costs to implement can be included into the problem formulation. That is to say, if a cost may be assigned to a load modification strategy as well as load modification profile resembling that of solar or wind generation profiles, then this load modification strategy can be one of the decision variables (expansion alternative) within the Generalized Benders' program, or can be analyzed using a prespecified pathway approach.

Section 8

STORAGE

8.1 PROBABILISTIC PRODUCTION COSTING-RELIABILITY

Storage will be treated in EGEAS in the context of a probabilistic
simulation production cost reliability model developed by MIT.* Some key
characteristics of the model are summarized here and its treatment of
storage is presented.

8.1.1 The Load Duration Curve

Electric power systems are operated with the goal of meeting the electric
demand at minimum cost. For a fixed set of generators, the dispatch
strategy that results in the minimum operating cost is to use the
generators in order of increasing marginal cost. In practice, this
strategy may be modified to account for operating constraints such as
spinning reserve requirements, high startup or shutdown costs and
transmission constraints. The final ranking of generators is called the
merit order or the economic loading order.

The power demand on an electric utility varies with the season and the
time of day. Figure 8.1a shows a typical daily variation in power
demand. Although the overall pattern is predictable, there is a large
random component that makes hourly predictions difficult. For this
reason, most planning studies use load duration curves that give just the

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*Finger, S., "Electric Power System Production Costing and Reliability
Analysis, Including Hydro-Electric, Storage, and Time Dependent Power
Plants," MIT-EL 79-006, February 1979, and "SYSGEN: Production Costing
and Reliability Model User Documentation," MIT-EL 79-020, July 1979.
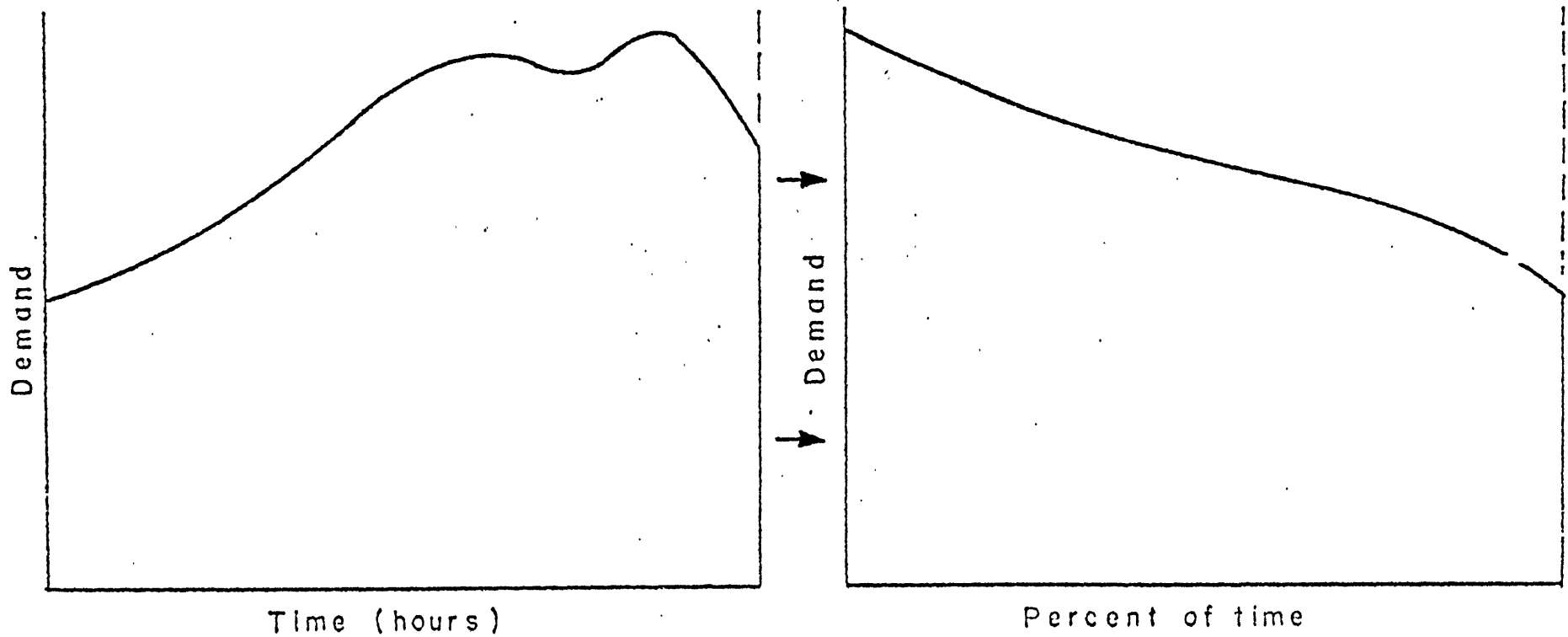
a Time-dependent load curve for a typical day.   b Load duration curve of a.

Figure 8.1   Conversion of time dependent curve to load duration curve.

percent of time that each demand level occurs. Figure 8.1 shows how a
time-dependent curve can be converted into a load duration curve.
Although detail is lost in the conversion, the load duration curve is
easier to work with for time periods longer than a day and for future
time periods for which there is not enough information to create hourly
curves.

If all available generating units were completely reliable, the operation
of the power system could be modeled by plotting the capacity of the
generators, in merit order, along the vertical axis of the customer
demand curve as shown in Figure 8.2a. The energy that a unit generates
would then be the area under the customer demand curve between its
loading point and the loading point of the next unit. Converting the
time-dependent curve into a load duration curve, as shown in Figure 8.2b,
leaves the loading point and the energy the same as in 8.2a.

However, generating units are not completely reliable, and hence their
forced outages have to be taken into consideration. Furthermore, hydro
and other limited energy plants, storage units, and time dependent
generation alternatives (solar, wind, cogeneration) are not dispatchable
the same way that conventional thermal units are. In order to handle
these issues, both customer demand and plant generation are treated as
random variables. The load duration curve is thus converted to a
probability distribution of customer demand exceeding a certain load
level as exhibited in Figure 8.3.

### 8.1.2 Treatment of Plant Outages Convolution

The load duration curve could be used as shown above to determine the
demand on a particular unit in the loading order, if it could be modified
to reflect the outages of all previously loaded units. This may be done
by computing the "equivalent demand" on a particular plant as the sum of
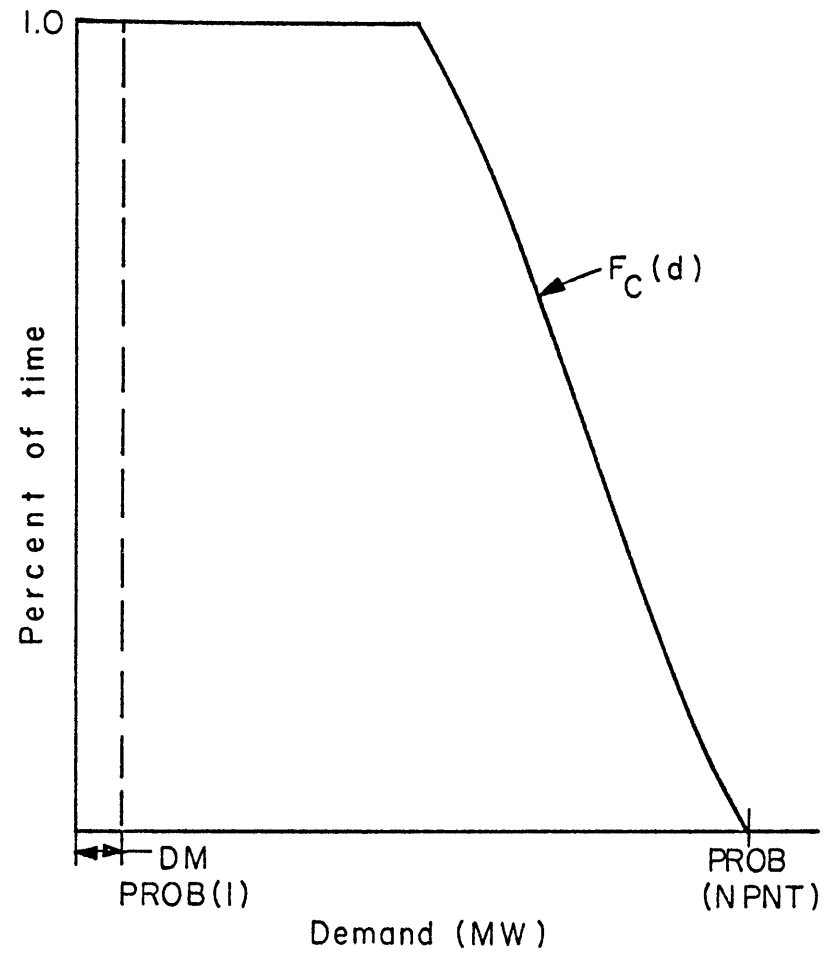customer demand and outages of previously loaded units.
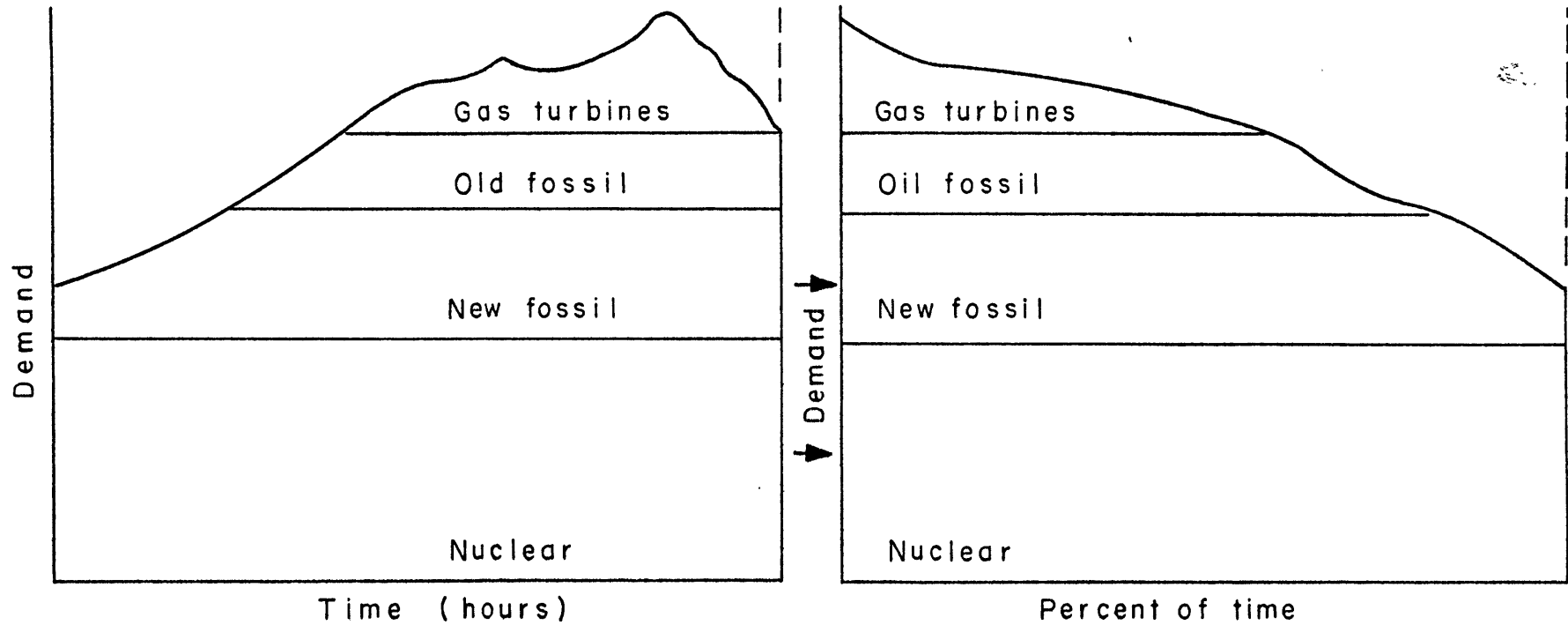
a. Typical operating schedule.

b. Equivalent schedule on a load duration curve.

Figure 8.2 Deterministic operating schedule.
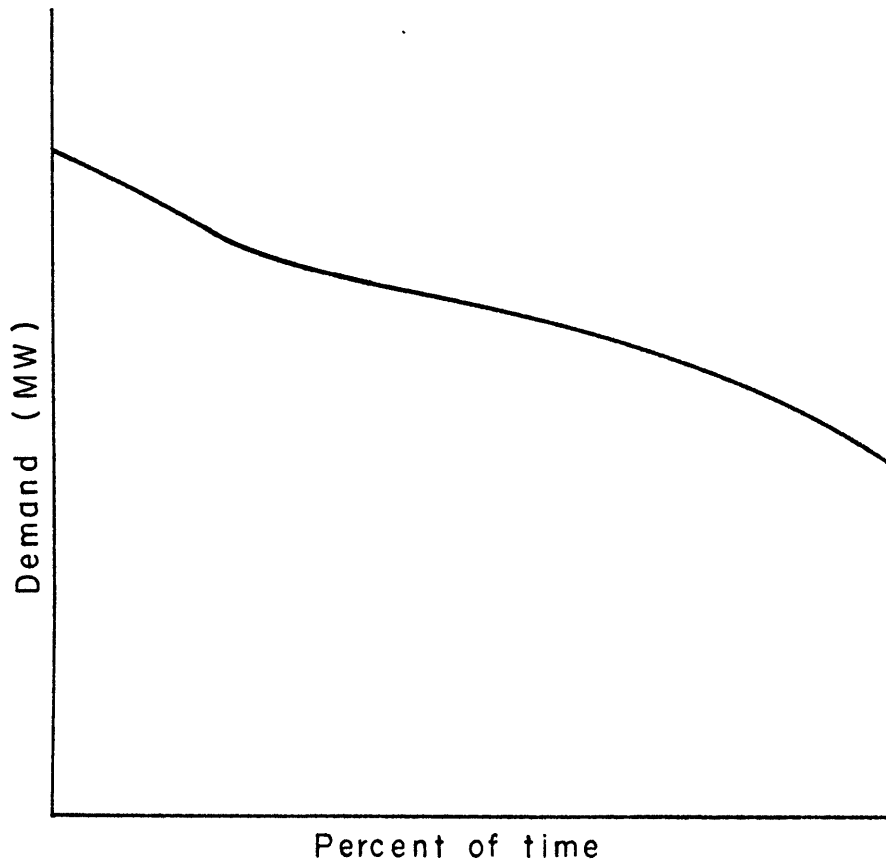
a. Original load duration curve.

b. Inverted load duration curve.

Figure 8.3 Conversion of load duration curve to cumulative probability curve.

For the case in which the forced outage rate of each plant with capacity K_i is a discrete random variable D_{F_i} with a probability mass function

$$P_F(D_{F_i}) = \begin{cases} p_i & \text{if } D_{F_i} = 0 \\ q_i & \text{if } D_{F_i} = K_i \end{cases}$$

$$p_i + q_i = 1$$

The "equivalent demand" on a unit given that d_i is the demand on unit i immediately preceding it in the loading order, is $d_i + D_{F_i}$. The "equivalent load duration curve" would then be for that unit,

$$F_{i+1}(d) = p_i F_i(d) + q_i F_i(d - K_i)$$

The above equation is the result of the addition of "convolution" of two random variables, d_i and D_{F_i}. Figure 8.4 illustrates graphically how the "equivalent load duration curve" on the second unit in the loading order may be found using convolution. This curve is used to find the expected energy generated by a particular unit as the product of the unit's availability (p_i) and the area under the curve between the unit's loading point and the loading point of the next unit. A new curve is computed each time a unit is brought on line. Finally, after the outages of all available units have been "added" to customer demand, the expected unserved energy may be obtained as an area under the curve, thus providing a measure of system reliability.

With time dependent units, the "addition" of unit outages is no more equivalent to the addition of independent random variables which is in effect the case with conventional plants. The dependence between customer demand and time dependent generation, as well as between alternative generations has to be carefully accounted for. However, the basic notion of the "equivalent load duration curve" remains in effect.

8-6
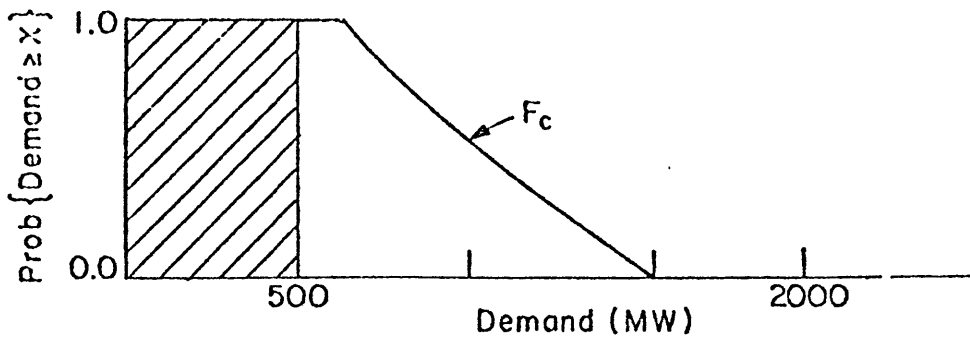
a   Loading of a 500 MW plant with 90% availability.
    Expected capacity (shaded area) = 500 MW.
    Expected energy = expected capacity x availability
    x hours = 75600 MWH/week
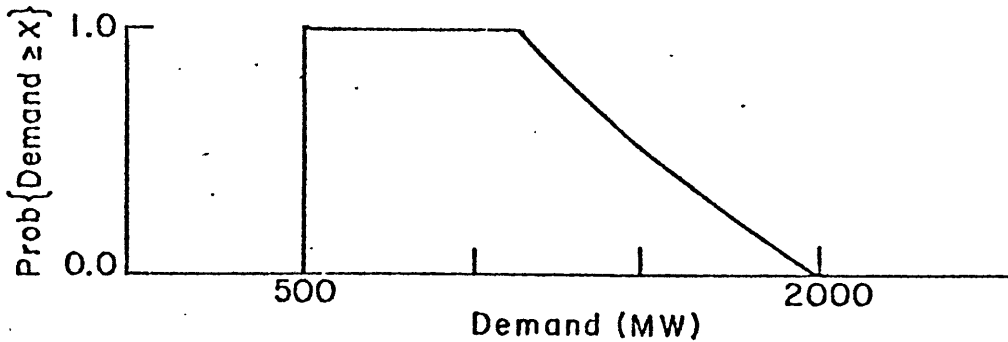
b   If the first plant fails, the second plant sees the
    original customer curve. This event has a
    probability of .10
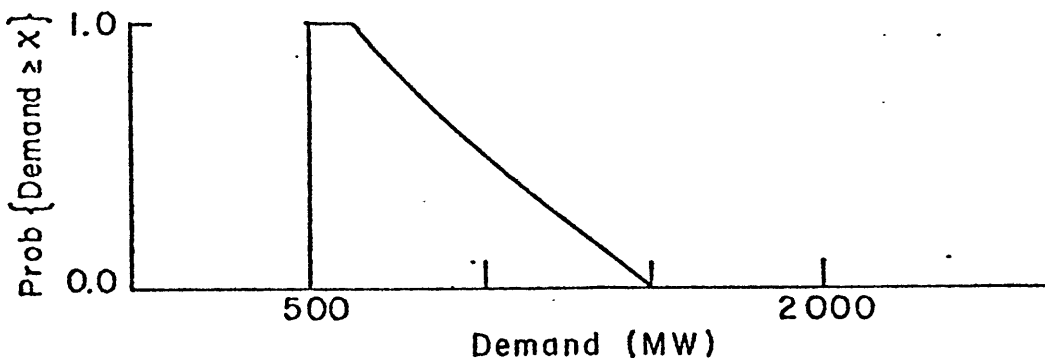
c   If the first plant operates the second plant does
    not see the first 500 MW of customer demand.
    This event has a probability of .90
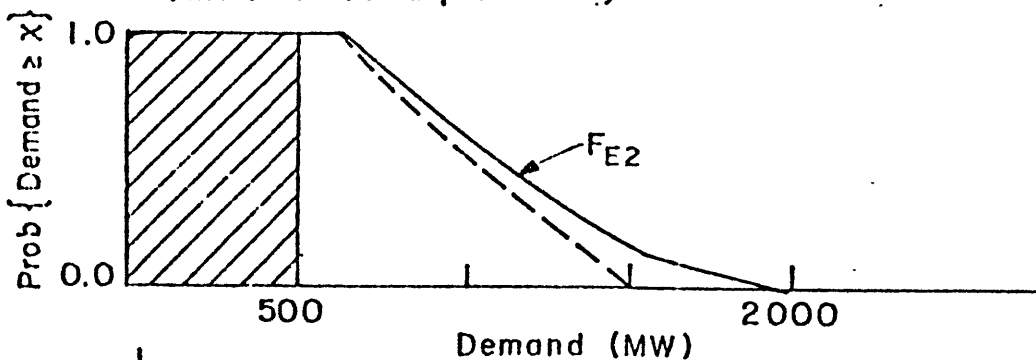
d   The equivalent load curve for the second plant
    is the sum of the two curves weighted by their
    respective probabilities

Figure 8.4   Graphic illustration of convolution

8.2 STORAGE IN A LOAD DURATION CURVE PRODUCTION SIMULATION MODEL

As was done with production costing, the treatment of storage units is briefly presented below assuming first completely reliable thermal generating units and then proceeding to the complete probabilistic treatment.

8.2.1 Storage with Completely Reliable Units

Electric utilities use storage plants to shift demand artificially from high marginal cost plants to low marginal cost plants. Currently, pumped hydro-electric storage is the only practical method available. Although the following section will refer to pumped hydro, the analysis is applicable to any central station storage unit that can be charged by all plants on the system.

Stored energy is generated by units which are low in the economic loading order, but that are not needed 100 percent of the time to meet the direct demand. Thus, an artificial demand is placed on these base loaded units by storage units . This stored energy can be released during periods of high demand when more costly units would normally be generating. Since the charging and discharging operations are not completely efficient, the energy available to meet demand using storage units is less than the energy generated by the base loaded units. Storage units are similar to conventional hydro units in that the amount of energy available is limited. However, modeling storage is complicated by the fact that the energy is not free and that the energy is generated on one part of the curve and discharged on another.

The total energy potentially available from a base loaded unit for storage can be found by computing the area above the load duration curve for the base loaded unit. Due to the limited capacity of the storage unit, some of this energy may be unavailable (see Figure 8.5a). Another limiting factor is the size of the reservoir. When the energy above the curve, subject to the limited capacity and the charging inefficiency, is equal to the storage capacity of the reservoir, then charging stops.

Taking into account the inefficiencies of generating from storage, the total energy available to meet customer demand will be about two-thirds the energy generated for storage. This results in a marginal generating cost about one and a half times that of the base loaded unit used for storage.

Depending on the system and shape of the load curve, several base loaded units may fill a single storage unit, or one base loaded unit may fill several storage reservoirs. For the completely reliable thermal units case, the marginal cost of the storage will be taken to be the average of the base loaded costs (with the inefficiencies factored in) weighted by the amount of energy each base loaded unit provides. If the storage units are ranked in order of decreasing number of hours at full capacity, then the first unit will be filled by the least expensive base loaded plant. Consequently it will be the first storage unit in the merit order after the storage units are sorted into the economic loading order based on the energy costs. When the first loading point is reached, the storage unit may have sufficient energy to discharge at full capacity, or it may not. The operating cost of the system is reduced by delaying the pumped hydro in the loading order until the demand can be met by using the pumped hydro at full capacity. The same is true for conventional hydro or other limited energy plants, even though the energy is no longer free. An illustration of the loading of pumped hydro is given in Figure 8.5.

8.2.2 Storage With Random Unit Outages

Once the energy available for storage has been computed, its treatment is similar to that of a limited energy plant. Namely, its loading point is chosen so that "equivalent demand" is met by using the pumped hydro at full capacity, provided that its cost is smaller than that of the cheapest competing in the loading order thermal plant. However, in order to find the energy available, the following values must be computed: (1) the expected excess energy available from base loaded units, given that each unit has a probability of failing; (2) the probability that a
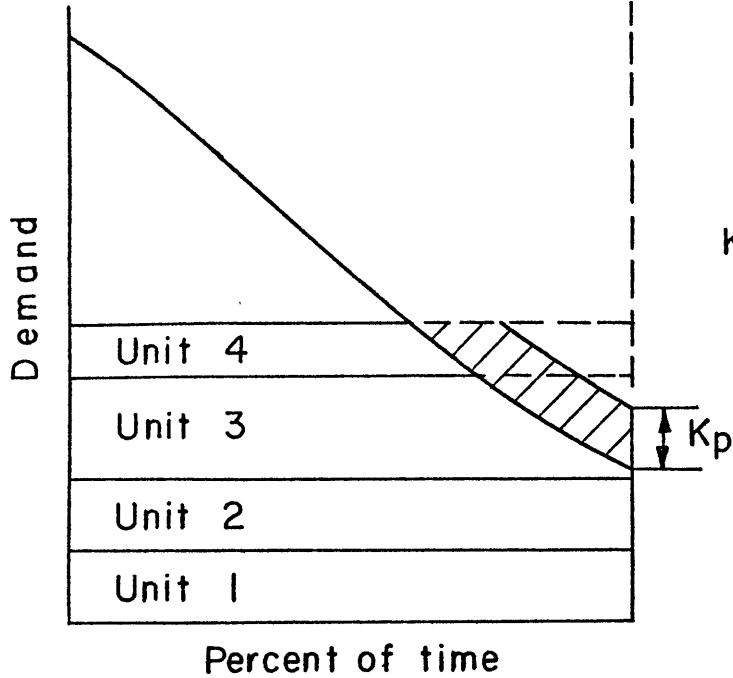
a. Shaded area is energy available for pumped hydro.
K_p = pumping capacity
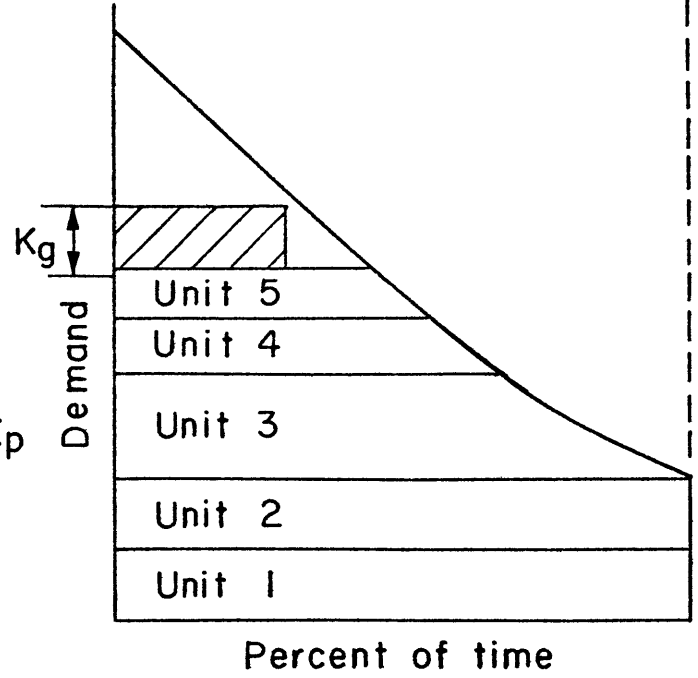
b. Pumped hydro unit is next in the economic loading order. Energy is reduced by pumping/generating inefficiencies.
K_g = generating capacity
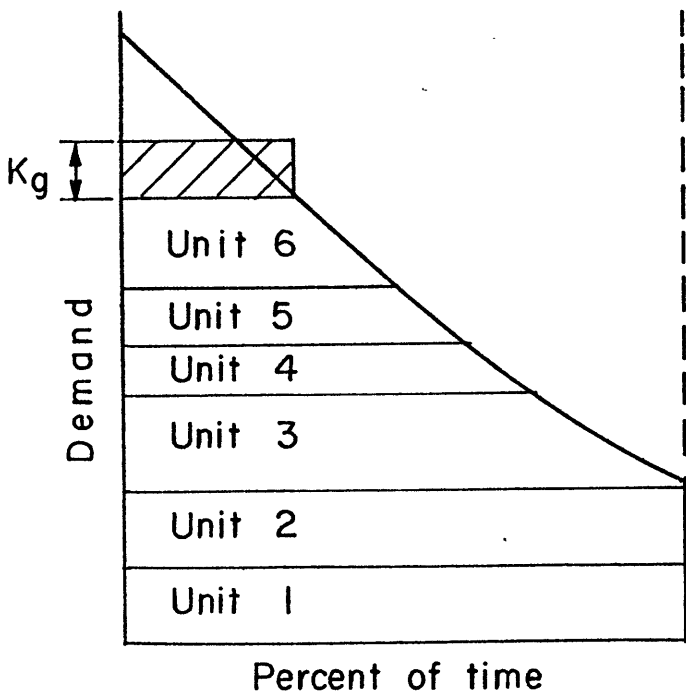
c. Loading of the pumped hydro is postponed until the energy available exceeds the energy demand.
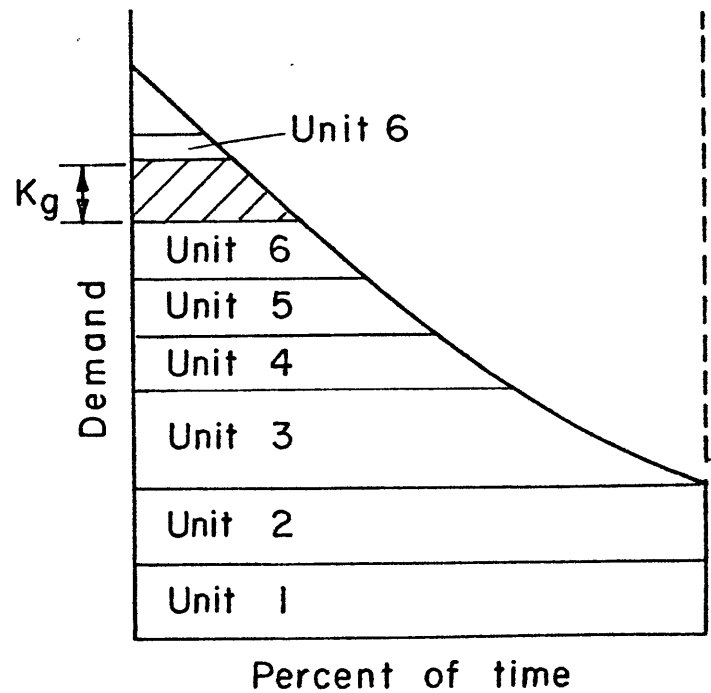
d. Unit 6 is loaded in increments to allow maximum discharge of pumped hydro.

Figure 8.5 Loading sequence for pumped hydro.

storage unit has sufficient energy available and the generator does not
fail; and (3) the expected cost of the stored energy.

A storage unit creates a demand on base loaded units; however, unlike the
customer demand, the storage demand does not necessarily have to be met.
Also, storage units do not impose outage demands on other units until
their place in the merit order is reached and they are called on to
generate. Therefore, a separate curve that includes the demand from
storage units on base loaded plants is created. This curve is used only
to generate information on the availability and cost of stored energy and
is unnecessary for the rest of the analysis.

The notation used in this section is the following: In general, the
letter 'f' is used for probability density functions, 'fq' for frequency
curves, 'd' for duration curves, 'G' for cumulative probability
functions, and 'F' for <u>reverse cumulative probability functions</u>. The
subscript of the function tells which random variable the function
describes. Thus $f_C(d)$ is the probability density function for the
customer demand, D_C. By definition:

$$f_C(x) = \text{Probability } [x \le D_C \le x + dx]$$

$$G_C(x) = \text{Probability } [D_C \le x] = \int_0^x f_C(y)\, dy$$

$$F(x) = 1 - G_C(x) = \text{Pr } [D_C \ge x] = \int_x^\infty f_C(y)\, dy.$$

The storage units are ranked so that the unit with the most hours of
generation at full capacity is the first to be filled. The ranking of a
storage plant relative to other storage plants is denoted by 'u' and is
distinct from the plant's ultimate place in the loading order, denoted by
'r'.

Each storage unit has the following characteristics:

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$$D_{su} = \text{demand for storage by unit } u$$

$$P_s(D_{su}) = \begin{cases} p_{cu} \text{ if } D_{su} = KC_u \\ q_{cu} \text{ if } D_{su} = 0 \end{cases} \tag{1}$$

where

q_{cu} = probability that the charging cycle of unit u fails
KC_u = charging capacity of unit u.

Note that the storage units impose demand on the base loaded units when they work. This is the reverse of generating units that impose outage demands when they fail.

- Energy Supplied to Storage

The demand imposed by storage units can be modeled as an increase in the customer demand. The equivalent augmented demand, D', can be defined as:

$$D'_{Er} = D_{Er} + KC_u \tag{2}$$

The distribution of KC_u is given in (1) and the distribution of D_{Er} is given by F_{Er}, the equivalent load curve for unit r. Convolving these distributions results in the distribution for the augmented demand:

$$F'_{ru} = q_{cu}F_{Er}(d) + p_{cu}F_{Er}(d - KC_u) \tag{3}$$

The expected capacity available for charging storage unit u from base load plant r is the area between F_{Er} and F'_{ru} as shown in Figure 8.6. This can be written as

$$E(C'_{ru}) = \begin{cases} \int_{d_{min}}^{U_{r+1}} F'_{ru}(x)dx - \int_{d_{min}}^{U_{r+1}} F_{Er}(x)dx \end{cases} \tag{4}$$

where

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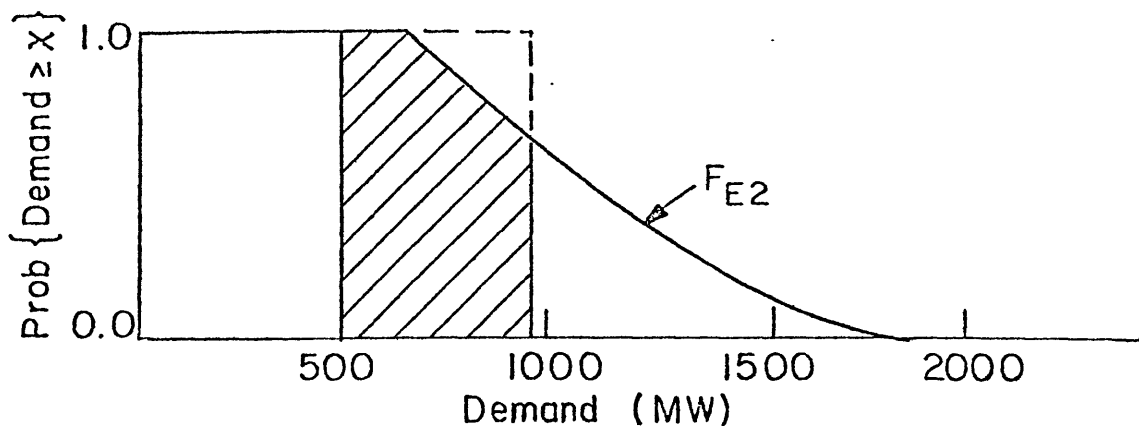
a Loading of second unit. Note that it could
   produce more energy if there were demand
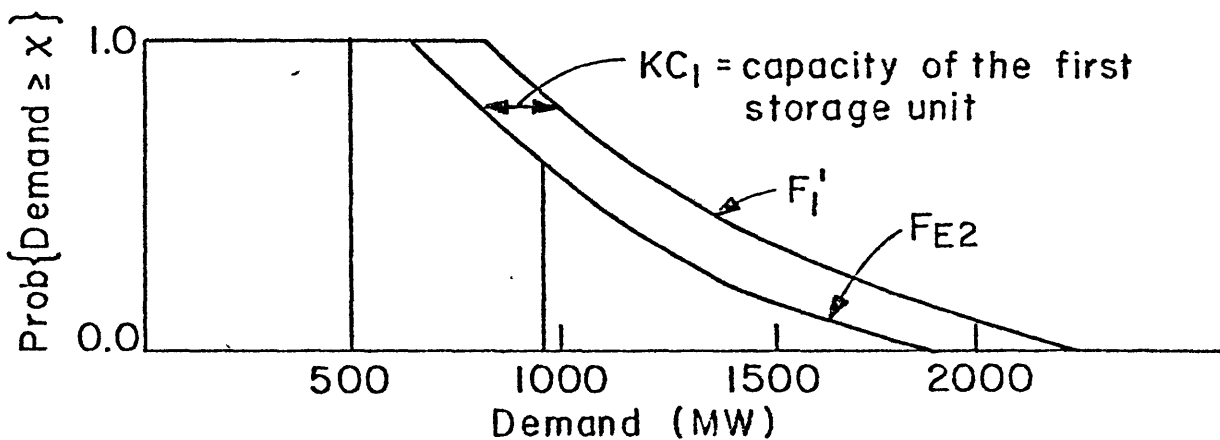
b The augmented demand curve, F', is created
   by convolving the demand created by first
   storage unit with the equivalent load on
   the second unit
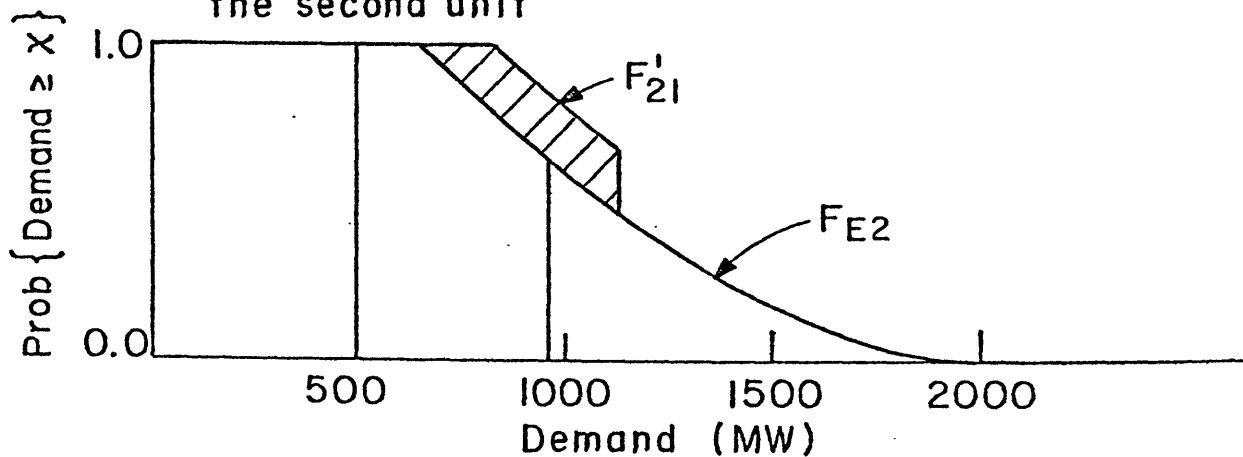
c The area between the equivalent demand
   curve and the augmented demand curve
   is the expected capacity available for
   charging storage unit I. This capacity
   is available with probability, P_2, the
   availability of the second unit

Figure 8.6   Storage demand on base loaded units
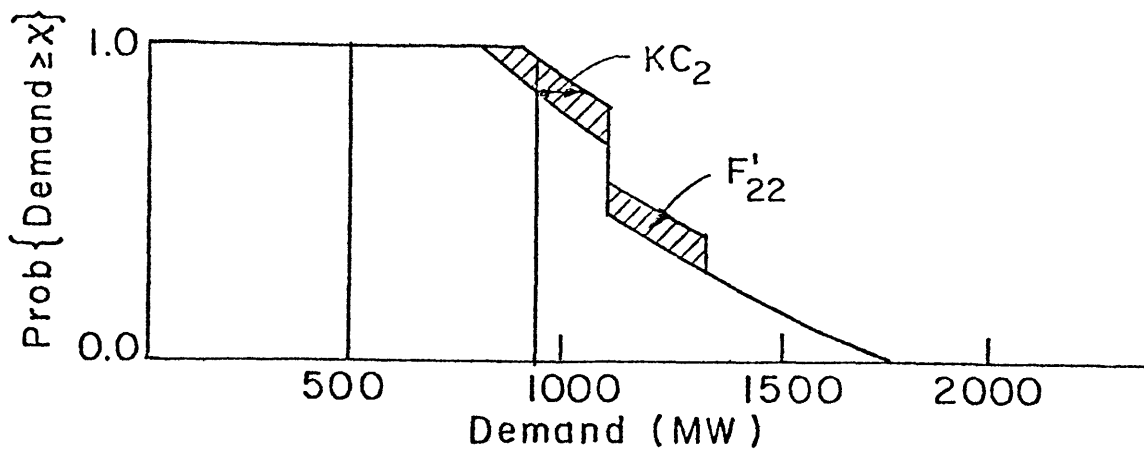
d. Loading of second storage unit onto the augmented demand curve
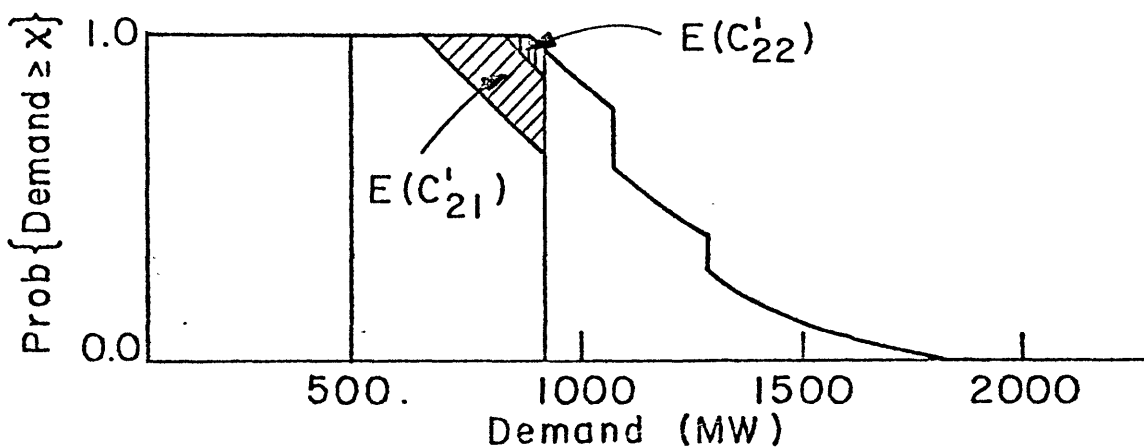
e. The area above the second unit is the expected capacity available for each of the storage units
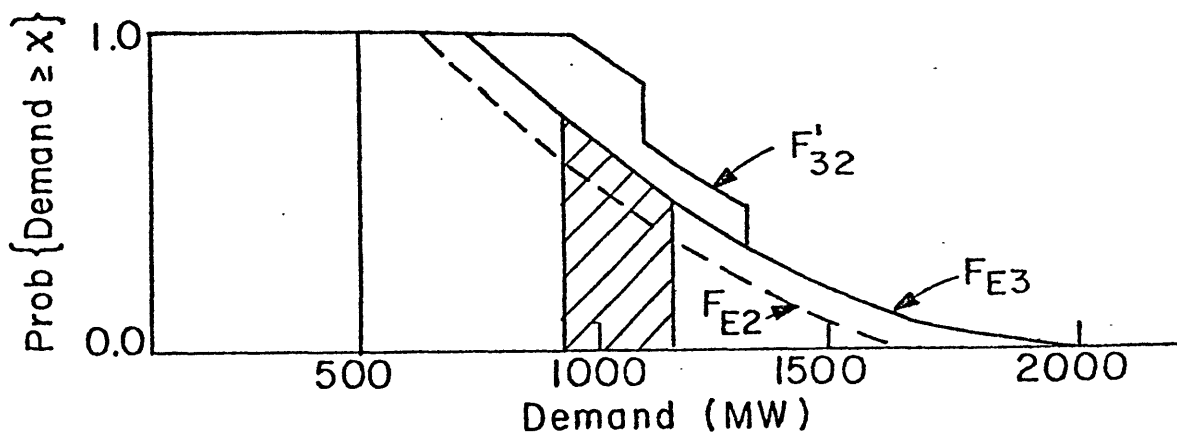
f. Loading of the third unit. A new equivalent demand curve, F_{E3}, and a new augmented demand curve, F'_{32}, are created

Figure 8.6 Storage demand on base loaded units

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d_{min} = minimum demand. This is the first point where $p[\text{demand} \leq x] < 1.0$

C'_{ru} = excess capacity available from unit r for storage unit u.

Combining equations (3) and (4):

$$E(C'_{ru}) = P_{cu} \int_{d_{min}}^{U_{r\pm1}} \left[F_{Er}(x - KC_u) - F_{Er}(x) \right] dx. \qquad (5)$$

This capacity is available with the probability of p_r, the availability of the base load unit. The expected energy available to the storage unit is the expected capacity multiplied by the time length and the availability of the base load plant.

$$a_{ru} = p_r E(C'_{ru}) \quad T \qquad (6)$$
where

a_{ru} = expected energy available from plant r for storage unit u.

Equations (2) through (5) imply that the storage demand is constant through time. However, the storage unit has a limited capacity and once the reservoir is full, the demand stops. Due to inefficiencies, the storage unit consumes more energy than its rated size, so pumping stops when the area between the curves, equals the total energy requirement, Z_u:

$$Z_u = z_u/e_u \qquad (7)$$
where

Z_u = total energy required by storage unit u

z_u = size of storage reservoir u

e_u = efficiency of storage unit u

The equivalent augmented demand curve can be written as:

$$F'_{ru}(d) = q_{cu}F_{Er}(d) + p_{cu}F_{Er}(d - KC_u) \qquad \text{for } d \leq d'_{u+1}$$

and

$$F'_{ru}(d) = F_{Er}(d) \qquad \text{for } d > d'_{u+1} \tag{8}$$

where d'_u is determined such that:

$$Z_u = T \quad p_{cu} \int_{d_{min}}^{d'_u} [F_{Er}(x - KC_u) - F_{Er}(x)]dx. \tag{9}$$

The resulting curve is shown in Figure 8.6c. This same curve could have been derived by adding the capacity of the storage unit to the original customer demand. However, the demand level at which storage starts and stops depends on the capacities and outage rates of earlier plants, so it is not possible to predict ahead of time when the storage demand will occur.

If there are additional storage plants, then they must also be added to the augmented demand curve. If the first storage plant were to fail, then the base load plant would supply the second storage plant instead.

$$F'_{ru+1}(d) = q_{cu+1}F'_{ru}(d) + p_{cu+1}F'_{ru}(d - KC_{u+1}) \qquad \text{for } d \leq d'_{u+1}$$

and

$$F'_{ru+1}(d) = F'_{ru}(d) \qquad \text{for } d > d'_{u+1} \tag{10}$$

where d' is determined such that:

$$Z_{u+1} = T \quad p_{cu+1} \int_{d_{min}}^{d'_u} [F_{Er}(x - KC_u) - F_{Er}(x)]dx \tag{11}$$

All storage units are loaded using equations (10) and (11).

The expected capacity available from base plant r for the first storage unit is given by:

$$E(C'_{r1}) = P_{c1} \int_{U_r}^{U_{r+1}} F_{Er}(x - KC_1) - F_{Er}(x) \, dx \qquad (12)$$

The expected energy available is:

$$a_{r1} = p_r \, T \, E(C'_{r1}) \qquad (13)$$

and the expected cost is:

$$c_{r1} = a_{r1} \, c_r \qquad (14)$$

To find the expected capacity available to the second storage unit, the equivalent loading point is increased by KC_1, the capacity of the first storage unit. Then,

$$E(C'_{r2}) = P_{c1} \int_{U_r + KC_1}^{U_{r+1} + KC_1} [F'_{r2}(x - KC_1) - F'_{r2}(x)] \, dx$$

$$a_{r2} = p_r \, T \, E(C'_{r2}) \qquad (15)$$

and the expected cost is:

$$c_{r2} = a_{r2} \, c_r.$$

Equation (15) is repeated until the expected energy supplied to each of the storage plants by plant r is found.

The next base plant in the loading order must supply whatever energy the first one could not due to outages, insufficient capacity, or insufficient energy. For the first storage plant, the augmented demand curve is given by

$$F'_{r+1,1}(d) = p_r F'_{r1}(d) + q_r F'_{r1}(d - K_r) \qquad (16)$$

and the expected capacity is:

$$E(C_{r+1,1}') = q_{r+1} \int_{U_{r+1}}^{U_{r+2}} [F_{r+1}'(x) - F_{r+1}' (x - K_r)]dx \qquad (17)$$

Equations (16) and (17) are much simpler than equations (10) and (12) because the demand due to storage is already included in F_{r1}'. The only additional factor that must be included is the probability that the first base unit fails and that the second must supply the additional energy to the storage unit.

In general for the first base load plant with excess energy

$$F_{ru+1}(d) = q_{cu} F_{ru}'(d) + p_{cu} F_{ru}' (d - KC_u). \qquad (18)$$

$$E(C_{ru}') = p_{cu} \int_{U_r+KC_{u-1}}^{U_{r+1}+KC_{u-1}} [F_{ru}'(x - KC_u) - F_{ru}'(x)]dx \qquad (19)$$

$$a_{ru} = p_r \, T \, E(C_{ru}')$$

$$c_{ru} = c_r \, a_{ru}$$

Finally, the expected energy and its cost for each storage plant are computed.

$$A_u = \left(\sum_r a_{ru} \right) \cdot e_u \qquad (20)$$

$$c_u = \left(\sum_r a_{ru} \, c_r \right) / A_u$$

The total expected energy and cost for the storage units cannot be found until all the base units have been loaded. There is an implicit assumption that the storage units will not be used before the base load units.

- Energy Supplied by Storage

The expected energy cost for storage unit u, as computed in equation (20) dictates the minimum spot it will have in the economic loading order. However, because the storage plant has limited energy, its use

may be postponed until all its energy can be dispatched at full
generating capacity in order to minimize the use of expensive fuels.

When a storage plant is loaded as a generator in position r in the
loading order, it has the following characteristics:

q_r = probability that the generator part of the cycle fails

K_r = capacity of the generator

A_r = expected energy available

c_r = expected cost per unit energy

λ_r = average forced outage occurrence rate

In theory the average forced outage occurence rate should be modified to
include the effects of the outages of base load units and other storage
plants. However, these effects are negligible and difficult to compute,
so they are ignored.

Section 9

INTERCONNECTIONS

Most electric power systems are involved to some extent with reserve
sharing and economy interchange with neighboring systems. The objective
of this task is the development of computer models within EGEAS that will
reflect the effect of ties to neighboring systems on reserve requirements
and fuel costs. The importance attached to effects of interconnections
on expansion planning of individual power systems will vary widely among
utilities.

The EGEAS interconnection model is designed to accommodate this wide
variety of utility requirements by providing several levels of detail and
sophistication to meet different utility needs and data availability.

9.1 GENERAL APPROACH

The interconnection model is designed to be compatible with the basic
structure of EGEAS. In particular, this means that the methodology is
based on the use of load duration curves. The data base for system A
(the system being optimized) is the same as that required by the basic
EGEAS program. Additional data required for system B are prepared in the
same format. Reserve requirements as affected by interconnections are
treated separately from economy interchange. Either or both these
options can be specified by the user.

In all cases, system A is being optimized and the characteristics of
system B remain fixed. For the most detailed formulations of the
interconnected model, system B generation expansion plans must be
specified in detail. For some of the simplified reserve requirement
models, few data are required for system B.

9.1.1 Economy Interchange

Economy interchange usually involves hour-by-hour interchanges between two parties based on a sale to one participant, whose running rate energy cost is high, from the other participant, who has a lower running rate. The sale price is computed as being midway between the two running rates so that the seller obtains more than his cost from the sale and the buyer benefits by replacing expensive generation with less expensive purchased energy. The total net savings is thus split equally between the participants.

The amount of the sale will consist of one or more blocks of energy from different generating units, each block will tend to reduce the differences in running rates until the running rates are equal, or until the tie lines reach a maximum transfer limit. The resulting unit dispatch is the same as that which would result from dispatching the two systems as though they were one.

It is not necessary to carry out this split savings computation for each hour to produce the net annual savings due to economy interchange. Each system may be dispatched for the whole year independently and dispatched again as one company. The difference in total annual fuel cost between the combined and independent dispatches will be the same as the savings produced by the hour-by-hour computations, provided that both computations are carried out deterministically.

The main difference between simulating economy interchange and the system dispatcher's hour-by-hour decisions in real time is that the simulated interchanges must be based on a probabilistic determination of the availability and cost of economy interchanges.

The basic methodology for determining the effect of economy interchange of system A fuel costs is based on three annual fuel cost dispatches: one of system A supplying system A load; one of system B supplying system B load; and one of the combined systems supplying the combined load. The

total savings in fuel cost is the difference between the sum of the independent fuel cost and the combined fuel cost.

The methodology for running three annual system dispatches provides accurate modeling of economy interchange savings provided that the ties are not limiting, even though the interchange consists of both purchases and sales. To make the methodology completely accurate, including tie line limits would require an hour-by-hour analysis. Even the hour-by-hour analysis would be further complicated by the probabilistic nature of the availability and cost of the economy interchange. It is possible to approximate the effect of limiting ties in the load duration dispatch methodology by converting the tie limit into an energy limit (MWH). This works well if the interchanges are all in the same direction but fails to consider the energy netted out by balancing purchases and sales. Any practical methodology must recognize the possibility of daily swings from purchases during off-peak hours to sales during peak load hours, and seasonal changes from purchases to sales. A compromise between a single annual load duration curve and hourly, probabilistic simulation to represent limiting ties will be provided by subdividing the load duration curve into off-peak and peak loads with further subdivision into months or seasons. A MWH limit will be applied separately to each subdivision and the purchase and sales. If ties are limiting, the limit will be applied first to interchanges that produce the smallest savings.

To this end, the generation of individual units in the purchasing system that participates in the interchange will be increased enough to reduce the purchase to an allowable amount. A similar decrease in participating unit generation in the selling system will also take place. Generation will be increased on participating units with the lowest fuel cost and decreased on units with the highest cost until the limit is reached.

Load diversity between the two systems accounts for a large percentage of the economy interchange and needs to be modeled accurately. To this end, hourly loads (in EEI format) will be provided for each year of the study for both systems. These loads will be summed hour-by-hour before the

load duration curves are formed for systems A, B, and the combined systems.

The split-savings method for pricing economy interchange may change in the future. Two additional options will be provided for determining the distribution of savings; one will consider split savings with a cap on the seller's profits; the other will provide for seller's cost plus a fixed percentage.

Storage will be represented in a straightforward manner within the three-dispatch methodology, i.e., system A storage will be dispatched with system A generation independently; system B storage will be dispatched with system B generation independent, and the combined storage will be dispatched with the combined systems. The resulting generation on the remaining units will determine the economy interchange.

The general equations and symbols relating to economy interchange are shown in Tables 9.1 and 9.2, respectively.

9.1.2 Reserve Sharing

When two or more systems are interconnected, the reserves are normally pooled so that emergency assistance is available to one system up to the limit of generating capacity reserve available in the remaining system. The amount of reserves that can be depended upon by a particular system within the pool may be limited either by transmission tie capability or by the probability that reserve capacity from the pool will be available when needed.

Three options will be provided to supply different system requirements.

- Option A

A simple model is justified for a class of small systems connected to very large interconnections. In these cases, reserves are available

Table 9.1

EQUATIONS

$$D = F_{A,I} + F_{B,I} - F_{A,C} - F_{B,C}$$

$$F_{A,T} = F_{A,I} - 1/2\ D$$

$$S_{A,N} = E_{A,C,N} - E_{A,I,N} \quad \text{(Positive)}$$

$$P_{A,N} = E_{A,I,N} - E_{A,C,N} \quad \text{(Positive)}$$

$$\text{Sale} = \sum S_{A,N}$$

$$\text{Purchase} = \sum P_{A,N}$$

$$\text{Maxsale} = K \cdot H \cdot T_S$$

$$\text{Maxpurchase} = K_P \cdot H \cdot T_P$$

If Sale > Maxsale or Purchase > Maxpurchase,

$$\text{Modify} = E_{A,C,N} \ \text{and} \ E_{B,C,N}$$

Table 9.2

SYMBOLS

$E_{A,C}$	=	System A annual generation in combined dispatch
$F_{A,I}$	=	System A annual fuel cost - Independent mode
$F_{A,C}$	=	System A annual fuel cost - Combined mode
$E_{A,I,N}$	=	Unit "N" generation in Independent mode
$E_{A,C,N}$	=	Unit "N" generation in Combined mode
$F_{A,T}$	=	Total fuel cost including economy interchange
T_S	=	Tie Line limit (Sale)
T_P	=	Tie Line limit (Purchase)
K_S	=	Tie line capacity factor (Sale)
K_P	=	Tie line capacity factor (Purchase)
D	=	Total savings due to economy interchange
$S_{A,N}$	=	Sale from Unit N, system A (Positive)
$P_{A,N}$	=	Purchase from Nnit N, system A (Positive)
H	=	Number of hours in load duration curve

with almost perfect reliability up to the limits of tie-line capacity.
For these systems, a tie line model may be selected that consists of a
single generator with no forced outage rate and a rating equal to the tie
line capacity. For this simplification to be valid, the tie line
capacity must be small with respect to the available reserves. The
advantage of this simplification is that it requires no data for sytem B.

- Option B

If a small systejm is interconnected with a large system by ties capable
of supplying all or a large part of the load, the model of option C below
may produce unacceptable results. For example, the neighboring systems
could supply the entire load. To supply a practical solution to this
problem, a limit on load to be supplied by the ties is provided. The
application of this option involves subtracting a fixed amount of load
from the load duration curves when computing reserve requirements.

- Option C

The methodology used in this option involves the develdopment of a
probability distribution of reserves available from system B.

For each year of the study a probability distribution of system B
generating capacity will be compiled by conventional methods used in
loss-of-load-probability calculations. From this distribution and the
system B peak load, the probability of available reserve will be
calculated in the form of a probability distribution of reserve
available. This list will be truncated at rated tie capacity. The model
developed from this probability distribution will resemble a multistate
generating unit with a separate forced outage rate for each level of
capability.

This synthetic unit will be added to the system A generator list and will
be loaded last in the probabilistic fuel cost simulation. As a result of
being last in the unit loading order, it will normally supply only

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"energy not served" by the remaining system A generating units. The tie-line model will be determined based on conditions at the time of system A peak load, and one model will be used for the entire year. More reserve may be available during other times in the year but reliability constraints are most sensitive to peak load conditions, and system B maintenance will tend to levelize reserves during off-peak periods.

A flow diagram is shown in Figure 9.1 for the development of all three models for Options A, B, and C. In all three options, a year-by-year file of the tie-line models will be developed and stored as indicated in Figure 9.1. Figure 9.2 demonstrates how these files are generated and used in the overall EGEAS structure.

The same tie line models will be used in OPTGEN and GEM. The models will be treated as "existing" units in the optimization process, the only difference being that the model changes each year.

```
                                    ┌──────────┐
                                    │  START   │
                                    └──────────┘

        ┌──────────┐          ┌──────────┐          ┌──────────┐
        │ OPTION A │          │ OPTION C │          │ OPTION B │
        └──────────┘          └──────────┘          └──────────┘
```

READ:

YEAR-BY-YEAR
NET INTERCHANGE
CAPABILITY

SEARCH INPUT FILE
FOR SYSTEM A
ANNUAL PEAK LOADS

DEVELOP TIE LINE
FILE CONSISTING
OF ONE UNIT FOR
EACH YEAR WITH A
CAPABILITY EQUAL
TO TIE CAPACITY
AND ZERO F.O.R.

READ:

% OF LOAD TO
BE SUPPLIED BY
TIES DURING
EMERGENCIES

DEVELOP TIE LINE FILE
CONSISTING OF ONE UNIT EACH
YEAR WITH CAPABILITY EQUAL
TO % OF PEAK LOAD AND
ZERO F.O.R.

READ:

SYSTEM B ANNUAL PEAK LOAD
LIST OF GENERATING UNIT
CAPACITY AND F.O.R. FOR
FIRST YEAR

COMPUTE:

PROBABILITY DISTRIBUTION
OF GENERATING CAPACITY
AVAILABLE FOR SYSTEM B

AND

PROBABILITY OF RESERVE
AVAILABLE IN EXCESS OF
SYSTEM B LOAD

UPDATE
GENERATOR LIST
FOR ADDITIONS
AND RETIREMENTS

DEVELOP TIE LINE MODEL
CONSISTING OF A MULTI-STATE
UNIT WITH A SEPARATE F.O.R.
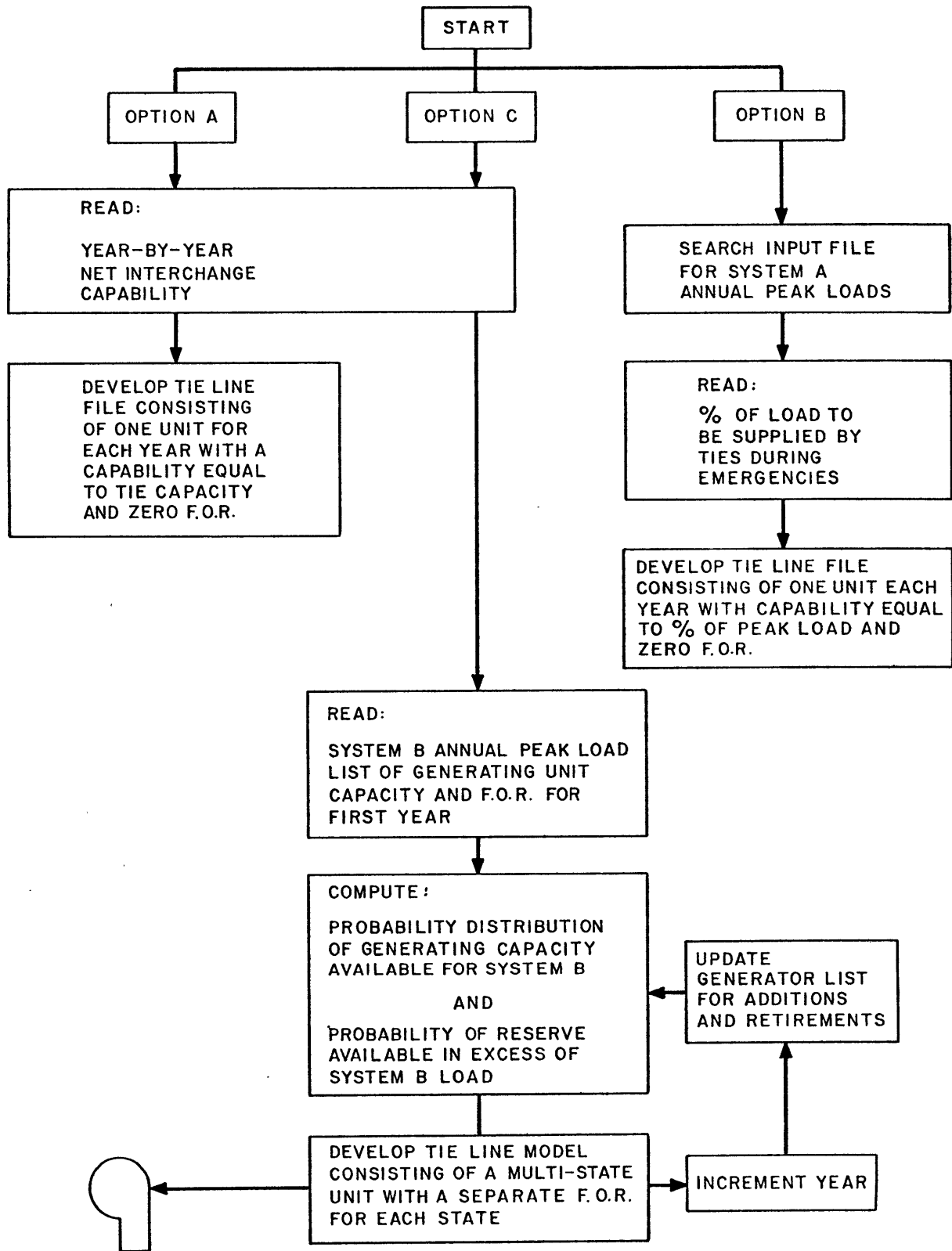FOR EACH STATE

INCREMENT YEAR

Figure 9.1   9-9
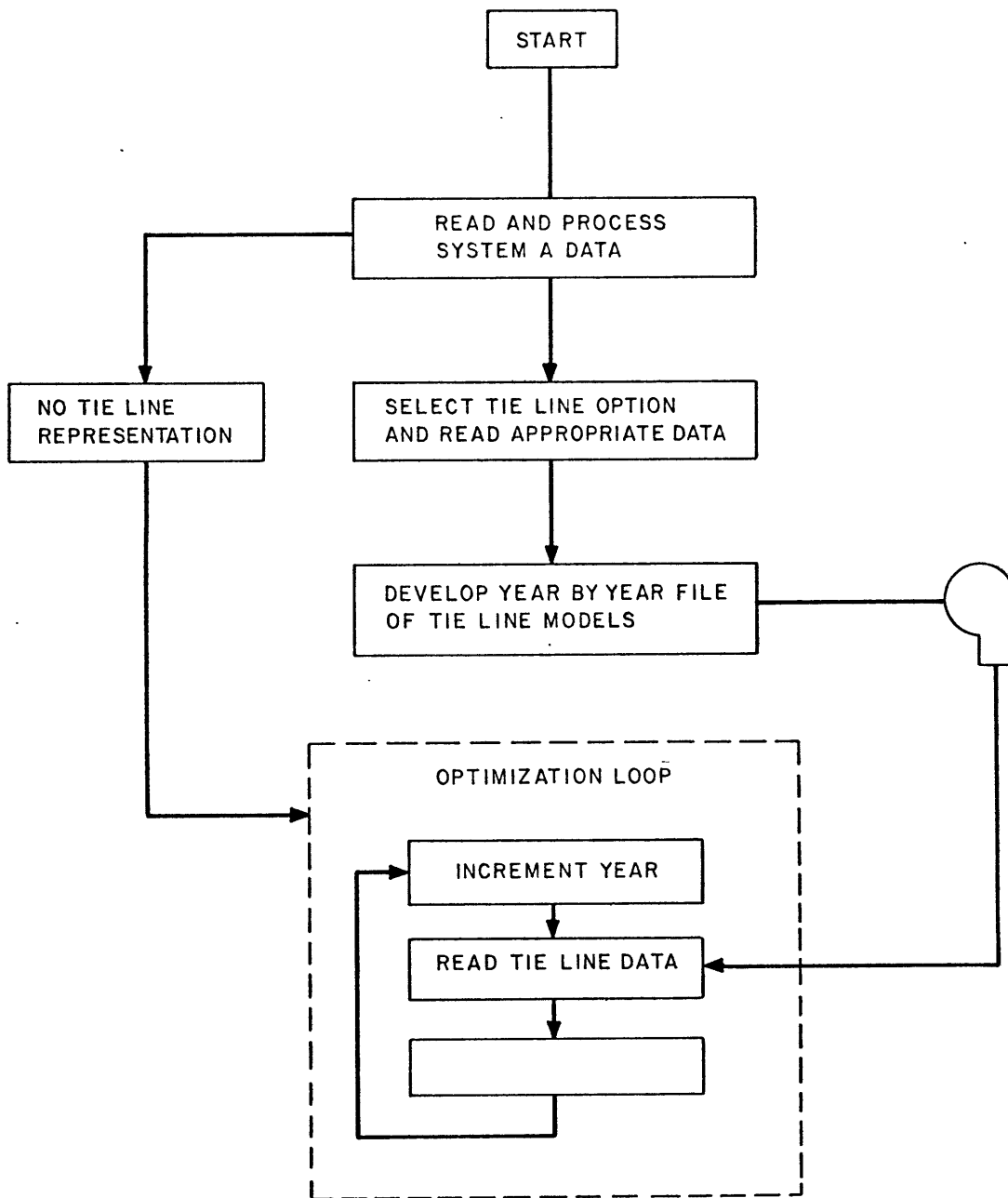
Figure 9.2

Section 10

OTHER ADVANCED FEATURES

Additional advanced features of EGEAS include addressing issues of
uncertainty, sensitivity analysis, and environmental considerations.
Work to date has proceeded with the conceptualization of the methodology
to be used in handling these features.

10.1 SENSITIVITY ANALYSIS

Sensitivity analysis can always be carried out via parametric variation,
an option available with all EGEAS modules. However, there are
significant limitations in this approach since it is adequate for the
study of only a limited number of input variations* and no systematic
relation may be derived between complex changes in a set of inputs and
their impact on output values. The method to be used in EGEAS can
provide such systematic relations by utilizing conventional sensitivity
analysis results to calibrate a "describing function" of changes in the
vector of outputs of an optimizing model as a function of a vector of
changes in the input parameters. The "describing function" approach to
sensitivity analysis has been developed by Schweppe and Gruhl** and is
briefly described as follows:

———————

*Interpolation is not applicable when more than one parameter is varied.

**Schweppe, F.C. and Gruhl, J., "Systematic Sensitivity Analysis Using
Describing Functions," published in S.I. Gass (ed.), Validation and
Assessment Issues of Energy Models, NBS 569, February 1980.

- A range of feasible values for each input whose actual value is not known with certainty is identified, so that it includes all "reasonably" probable variations of the input's uncertain value.

- The joint probability distribution of input vector perturbations is then described and a set of perturbations which span the range of probable variations is determined.

- Conventional parametric analysis is performed by running the optimization algorithm for each input perturbation in the above set to obtain the corresponding output perturbation.

- Statistical estimation is then utilized to derive a polynomial function which transforms perturbations in inputs to perturbations in outputs. The statistical estimation technique uses input-output perturbations obtained by conventional parametric analysis and the probability distribution of input perturbations to calibrate the describing function, selecting at the same time endogenously the necessary complexity of the polynomial function (degree of polynomial, number of cross products, etc.). The degree of complexity is chosen to minimize the difference between the mean square of "predicted" by the describing function variations and the mean square of "actual" variations. Finally, the estimation procedure indicates whether the number of sample relations between input and output variations obtained through conventional parametric analysis is sufficient for statistically significant calibration of the describing function. If needed, additional runs of the otpimization algorithm are performed to provide a more dense span of the range of probable input variations.

With an analytic representation of the impact on output of variations in the inputs, the sensitivity of the optimal decisions on input variations may be clearly investigated in a systematic and exhaustive manner.

10.2 UNCERTAINTIES

The following options are currently being investigated as candidates for the treatment of uncertainties in EGEAS.

10.2.1 Assessment of Uncertainty Impact

The degree to which the optimal plan must be revised as a result of the realization of different from expected events (demand growth, regulation, costs, etc.) must be carefully determined. This effort is an extension of sensitivity analysis discussed above, and will utilize conventional parametric analysis and the "describing function" approach. Uncertainties which do not affect the optimal plan significantly may thus be screened before building the decision tree discussed below.

10.2.2 Sequential Decision Update

A utility has the flexibility to react to the occurrence of actual outcomes differing substantially from expectations on the basis of which decisions were taken in the past. The extent to which a utility may adjust (i.e., suffering a higher or lower cost) depends on the particular characteristics of the utility, the existing and committed units, the regulatory regime, the growth of demand, etc. An assessment of a utility's ability to adjust may be obtained by simulating its sequential investment decision updating as follows:

- Construction of Decision Tree
On the basis of sensitivity analysis the assessment of uncertainty's impact may be performed and the variables whose variance affects investment decisions significantly identified. The uncertainty associated with possible values these variables may take in the future will have to be modeled in terms of discrete probability distributions reflecting dependencies among variables. These discrete joint probability distributions will then be used to construct a decision tree representing all possible ways in which uncertainty may resolve itself in the future. An example of such a decision tree is given in Figure 10.1

- Simulation of Sequential Decisions Along the Branches of the Decision Tree

The simulation of sequential decisions involves successive runs of a capacity expansion option. Each run should have a starting period which coincides either with the beginning of the initial planning period $(t_{start} = t_0)$ or with the time that an uncertainty resolves itself in the decision tree $(t_{start} = t_n)$. Further, the input on the basis of which each run will be made should be derived in part from a previous run (endogenous state variables, EN) and in part from decision tree specified uncertain variable values (exogenous state variables, EX) corresponding to the most likely values conditional upon the uncertainty resolution defining the particular branch of the tree the planner is simulating.

For a more detailed description of sequential decision simulation the following variables have to be defined:

   T: Length of planning period

   $A_{t_n}(j)$:   The resolution of uncertainty during time period t_n is described by realization j

   $EX_{t_n}(j)$:   Exogenous state variables at time t_0 corresponding to the most likely values of the uncertain variables conditional upon $A_{t_n}(j)$. Such variables may include:

   o   costs
      o   fuel, capital, plants
   o   reliability
      o   outage rates
   o   load demand
      o   growth
      o   load shape
   o   constraints
      o   fuel, capital availability
      o   environmental/regulatory/financial
      o   reliability.

The above variables are exogenously supplied by the user on the basis of $A_{t_n}(j)$.
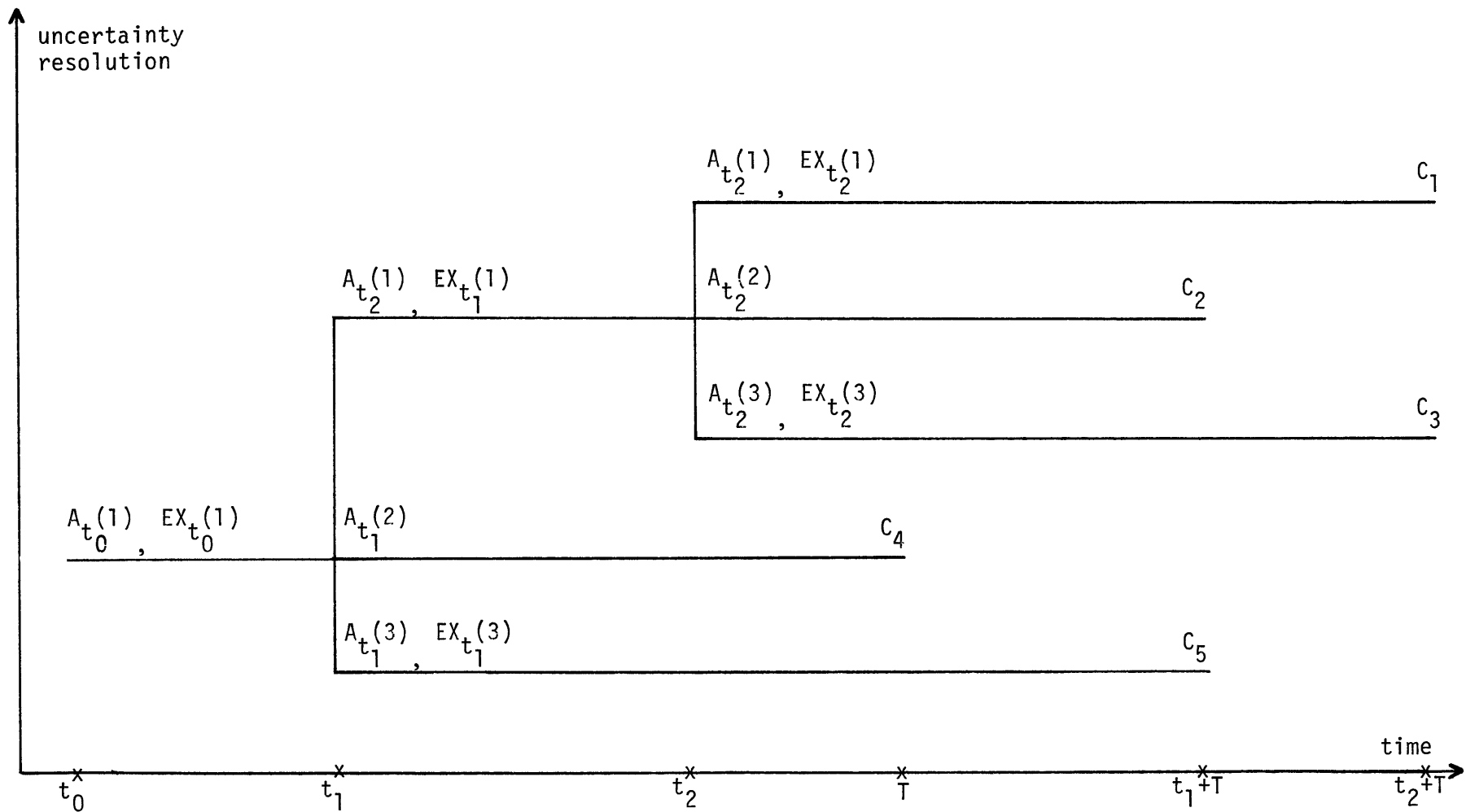
Figure 10.1.   Example of a decision tree.

Note: $A_{t_1}(2)$:   most likely resolution given $A_{t_0}(1)$.

$A_{t_2}(2)$:   most likely resolution given $A_{t_1}(1)$.

$EN_{t_n}(i)$: Endogenous state variables at time t_n corresponding to optimal decisions over the period t_{n-1}, $t_{n-1} + T$ on the basis of $EX_{t_{n-1}}(i)$, the most likely values of exogenous state variables conditional upon an uncertainty resolution during time period t_{n-1} described by $A_{t_{n-1}}(i)$.

Such variables may be:

o   usage to time t_n

    o   fuel, capital, air, water, sites, resources

o   large reservoir storage levels at time t_n

o   installed plants at time t_n

o   committed plants at time t_n

The above variables are derived from the output of a previous run of the capacity expansion option used in the simulation, over the period t_{n-1}, $t_{n-1} + T$ with input $EN_{t_{n-1}}(k)$ and $EX_{t_{n-1}}(j)$ where k,j are indices defining the decision tree branch over which the user is simulating.

$D_{t_n}(i,j)$: Decision variables over the period t_n, $t_n + T$ corresponding to endogenous state variables $EN_{t_n}(i)$ and exogenous state variables $EX_{t_n}(j)$. Such variables may include:

o   capacity

    o   type

    o   amount

    o   timing

o   dispatch.

The following example describes the uncertainty treatment capability whose incorporation into EGEAS is under investigation. Referring to the decision tree in Figure 10.1 in order to simulate sequential decisions over the branch $A_{t_0}(1)$, $A_{t_1}(1)$, $A_{t_2}(3)$, C, the user would have to specify exogenously

$EX_{t_0}(1)$: The base case "most likely" values of uncertain variables over the period t_0, T

$EX_{t_1}(1)$: The most likely values of uncertain variables over the period t_1, t_1 + T conditional upon uncertainty resolution $A_{t_1}(1)$

$EX_{t_2}(3)$: Similarly over t_2, t_2 + T conditional upon uncertainty resolution $A_{t_2}(3)$

$EN_{t_0}(0)$: The presently committed and existing plants, storage levels, etc.

The EGEAS control program will then run the user selected optimization option to generate

a. D_{t_0} using as input $EX_{t_0}(1)$ and $EN_{t_0}(0)$

b. $D_{t_1}(1,1)$ using as input $EX_{t_1}(1)$ and $EN_{t_1}(1)$

c. $D_{t_2}(1,3)$ using as input $EX_{t_2}(3)$ and $EN_{t_2}(1)$

d. $EN_{t_1}(1)$ and $EN_{t_2}(1)$, derived from D_{t_0} and n_{t_1} 1 1) respectively

The user can then recover from D_{t_0}, $D_{t_1}(1,1)$, $D_{t_2}(1,3)$ plant installations and commitments during the period t_0, t_0 + T corresponding to sequential decision updates or reoptimizations which will take place if uncertainties resolve themselves according to decision tree branch $A_{t_0}(1)$, $A_{t_1}(1)$, $A_{t_2}(3)$, C_3.

Upon simulation over all decision tree branches the user can employ uncertainty resolution probabilities to estimate expected costs of capacity expansion. It should be noted that each of the successive runs in the sequential decision simulation is a deterministic decision algorithm. The use of formal stochastic optimization (expected cost minimization) is a feasible extension, especially with the Generalized Benders' capacity expansion option, but one which cannot be realized under present funding constraints.

10.3 ENVIRONMENTAL CONSIDERATIONS

The environmental interface extension to the EGEAS database will include the actual limits on total emissions within a site (or area) and within the total system. These will be in the form of total mass of SO_2 or particulates allowed, mega-gallons of water consumed, MBTU of heat output and total acreage of land used. Fuel data pertaining to SO_2 (and particulate) content and emission factor must also be provided as well as removal efficiencies for various pollution abatement technologies.

The matrix generator of the LP module will allow for any of the emission constraints, for individual site and/or total system, to be turned on or off in any year, independently. This will allow the planner to keep the problem size manageable by turning on constraints selectively. Further, a constraint limiting total output of any emission type over the entire planning period will be allowed. A basic assumption used by the LP approach is that emissions are a linear function of plant capacity and energy output. Section 4.1.2 provides further detail about the actual equations used in the LP.

The decomposition technique will treat emission constraints in the same manner as energy limitations (e.g., fuel availablility constraints). The same flexibility will be provided in the master problem matrix generator as will be in the LP, allowing emission constraints to be turned on or off independently in any year. If fuel constraints are also included within a run, only the more binding constraint (emission or fuel) will be written by the matrix generator. The basic procedure has the master problem selecting plant capacities and energy output limitations, and the subproblem operating on this set of information, calculating Lagrange multipliers for the capacities and energies (which are then fed back to the master problem for the next iteration). An assumption here is that emissions are a convex function of the energy output of a plant.

The dynamic programming (DP) module may deal with environmental constraints by performing post-production cost screening of individual states to ensure that constraints are not violated. The viability of this

approach is still being researched. Currently it is felt that by performing the environmental screening, states may be eliminated during a given year as well as future states which extend from the screened states. Elimination of future states could even cause a net savings in computer run time if the screening calculations themselves are not too costly. Within the DP approach, emissions can be assumed to be any linear or non-linear function of plant capacity and energy output. Also under consideration for use in the DP is the use of energy limitations within the production cost module (similar to the decomposition approach). It should be emphasized that these DP approaches are still being researched and are not necessarily going to be included in the EGEAS package.

The external environmental data base will contain basic site information which would allow for standard point-source dispersion modeling to be performed. Such data would include "wind rose" data (wind velocity vector information), ambient conditions relating to ground level concentration of SO_2 and particulates as well as water flow, depth, width, temperature, and classification (river, estuary, etc.). Screening standards can also be input to allow the user written dispersion models to perform plant/site screening on a generic level, or to perform trade-off analyses pertaining to the size of abatement technologies required to meet given standards.

In keeping with contract requirements, the above statements on EGEAS' handling of environmental concerns do allow for its inclusion as a supply planning package into a methodology as set forth in the PHASE I final report by the Massachusetts Energy Facilities Siting Council to the U.S. Nuclear Regulatory Commission entitled "An Integrated Regional Approach to Regulating Energy Facility Siting." This basic methodology is illustrated in Figure 10.2 .

DEMAND
BACKGROUND
STUDIES*

o Population
  Growth

o Load
  Management
  Schemes

SUPPLY
BACKGROUND
STUDIES*

o Assessment of
  Alternate
  Technologies

o Fuel
  Assessment

o Existing
  Systems

o Economic

ENVIRONMENTAL
BACKGROUND
STUDIES*

o Future water
  Availability

o Air Quality

o Health Effects

o Technology
  Assessment

DEMAND
FORECASTING

SUPPLY
PLANNING

SITING
ANALYSIS

Review/
Feedback

ENVIRONMENTAL
SCREENING

Yearly
Peak and
Load Shape

Demand by
Load Centers

Site types,
Yearly mix,
Capacity

Siting Patterns,
Costs, Impacts
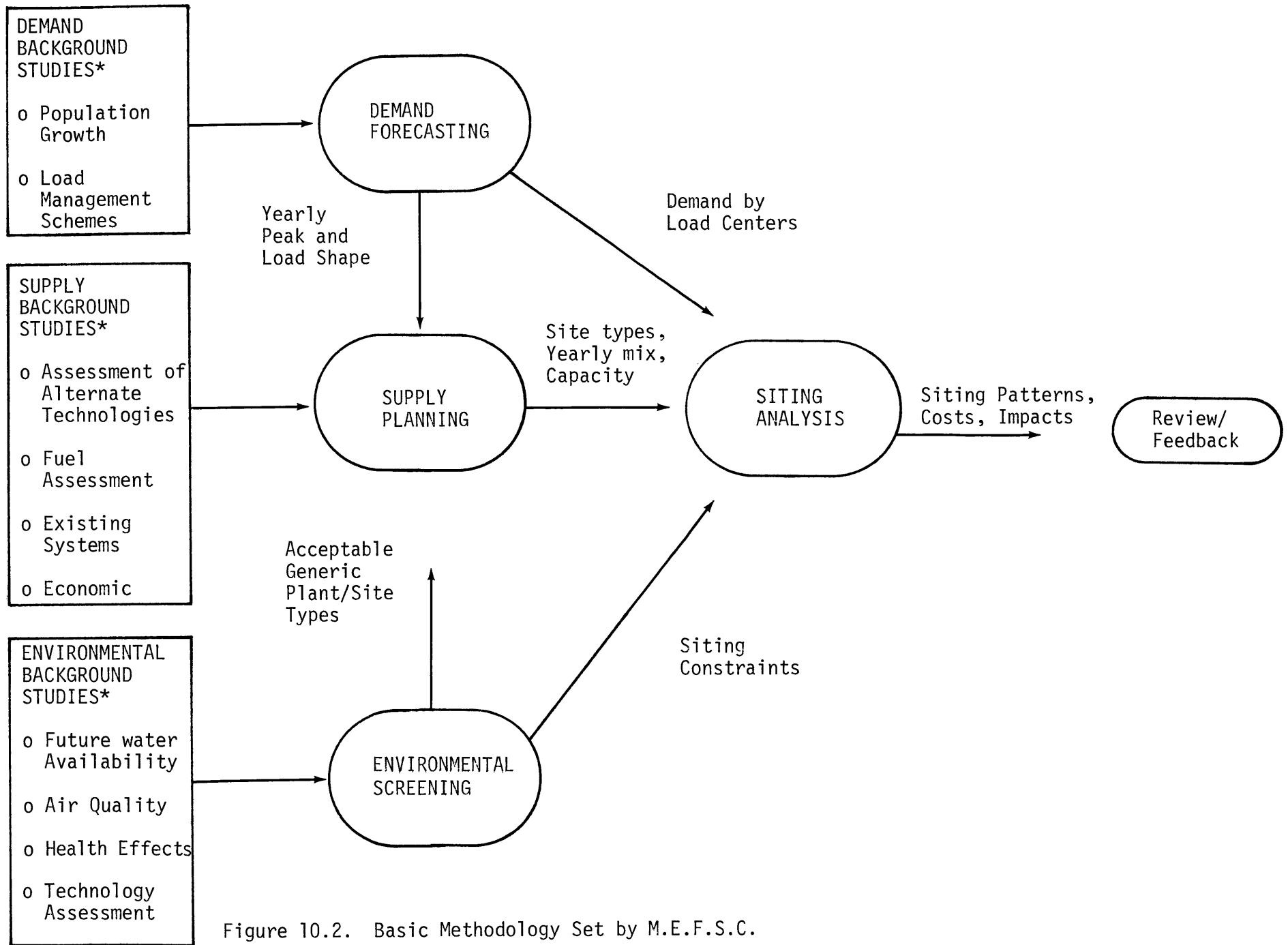
Acceptable
Generic
Plant/Site
Types

Siting
Constraints

Figure 10.2.   Basic Methodology Set by M.E.F.S.C.

Section 11

TESTING AND VALIDATION CRITERIA

Once the mathematical model has been developed, it is necessary
to analyze its structure and the data generated by its computer
implementation before the model can be considered credible. In
this task we distinguish three separate activities:

1. Mathematical verification, which is accomplished in the
analytical stage of model building,

2. Computer program verification, which is accomplished during
computer implementation,

3. Model validation.

The purpose of (1) and (2) is to eliminate unintentional logical
errors in the model's structure, the mathematical solution
algorithm and the corresponding computer program. That is, to
make sure that the model is developed and implemented as
intended. To some extent this objective is independent of the
quality of numerical results or their relation to the behavior
of the prototype. Model validation is another stage of
modeling; it usually includes:

1. Analysis of the quality of mathematical formulation,
solution algorithms and numerical results;

2. Comparison of the numerical responses from the verified
model with corresponding responses or measurements recorded from
the prototype;

3. A combination of 1 and 2.*

11.1 INTRODUCTION

The EGEAS system testing procedures will be carried out in accordance

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*Samuel Jacoby and Janusz Kowalik, Mathematical Modeling with Computers
(Englewood Cliffs, NJ, Prentice Hall, 1980), p. 216.

with accepted structured programming practices and will, in general form, follow the distinctions drawn above by Jacoby and Kowalik. The initial step in the testing procedure has been to develop a set of behavioral objectives, one for each major component in EGEAS.

11.2 OBJECTIVES

The discussion below presents the behavioral obectives of each major component of EGEAS. It is against these initial objectives that the performance of EGEAS will be measured. They cover, briefly the scope of the activities, and input and output requirements.

Dynamic Programing

EGEAS shall contain dynamic programming algorithms capable of analyzing limited numbers of expansin alternatives (up to a limit of 5 with the most common runs containing only 3 or 4 expansion alternatives). The dynamic programming algorithms shall be accessed through the central EGEAS controller and shall access the common EGEAS data base. It shall be capable of outputting the 100 best solutions.

Linear Programming

One analysis option within EGEAS will be a linear programming optimization. A matrix generator will be provided which can generate constraints in any time period (and one for the sum of all time periods where applicable) for any of the following issues:

o   system peak load plus margin

o   system total energy served (broken down into at most 3 types - base, intermediate, and peaking)

o   fuel usage by fuel type and grade

o   emissions by site for total system for SO_2, particulates and thermal

o   land use by site or total system

o   water consumption by site or total system

o   available sites

Any of these constraints can be turned on or off in any year, thus
allowing flexibility of use and computational feasibility. The objective
function is to minimize Present Worth of Revenue Requirements which is
the Present Worth sum of fixed and variable system costs, both within the
planning horizon and in the extensin period. The decision variable will
be continuous, not integer in values for number of plants built.

The linear programming package shall be accessed through the central
EGEAS controller, and shall access the common EGEAS data base.

Generalized Benders'

EGEAS shall contain an algorithm which will provide optimal capacity
expansion decisions based on detailed accounting for fixed and variable
costs as well as satisfying reliability constraints with respect to
unserved energy. The algorithm shall be an extension of Generalized
Benders' decomposition which allows iterations between a linear program
and a simulation production costing program in order to arrive at the
optimal solution. The Generalized Benders' algorithms shall be accessed
through the central EGEAS controller and shall access the common EGEAS
data base.

Data Base

The data base for EGEAS will be structured to allow access by various
analysis options (through a single controller program). It will contain
a central data base, which will include the necessary and sufficient
parameters for performing conventional capacity planning analysis.
Interface Extensions will be provided which can be added if various
advanced features are to be run. The data base will be composed of a
master file and a study variations file, which can temporarily override

assumptions on the master file without changing the contents of the master file. The master file will have maintenance routines. Error-checking routines will be provided. Also, data accessing routines will be provided to increase flexibility and ease of data base use.

Sensitivity Analysis/Uncertainties

The central EGEAS controller and the common data base shall be designed so that "automatic" parametric sensitivity analysis is an option to the EGEAS user with all optimization/simulation modules contained within the EGEAS code. In addition, the capability to estimate the parameters of a "describing function" will be included. The "describing function" has the form of a polynomial and provides an analytic representation of the impact on output values resulting from changes in the input values.

Storage

EGEAS shall contain algorithms capable of studying/optimizing storage systems. These algorithms shall consist of a probabilistic production costing technique utilizing a Load Duration Curve representation of demand.

Interconnections

The interconnection model will provide capability to model the effect of tie lines between the user's system and neighboring systems. The ties may be used to reduce reserve requirements or to provide lower fuel costs through economy interchange. The neighboring system or systems will be modeled as one system. Two optimization modes will be provided. One will optimize the user's sytem based on a fixed, known expansion plan for the neighboring system. The other will optimize both systems as a pool and provide an allocation of costs, capacity purchases and sales, and ownership of new capacity for the user's system. A split savings economy dispatch will be used for both modes.

11.3 VERIFICATION

Mathematical verification and program verification (testing) will be accomplished in parallel with the programming activities. The procedures used for the testing of the EGEAS program coding will be a synthesis of top/down and bottom/up parallel testing. The EGEAS system specifications and functional code specifications developed in Task II will detail the program modules comprising the system as well as the required module interfaces. Vertical branches will be developed for all modules defined in the specifications on a macro level so that top/down testing sequences can be identified. For example two typical branches would be:

a) Edit Program, Report Program

b) Control Program, Optimization Program, Report Generator Program

This portion of the testing will be performed as the coding is developed. Only controilled testing will not be undertaken since the primary purpose for early development and testing of this portion of the coding is to define and set all program interfaces as soon as possible.

These vertical macro branches such as a) and b) above will be further defined into more detailed micro branches depicting the major processing modules within each program such as Input/Output, technical algorithms, and internal controllers. From these branches subroutines and functions will be grouped into logical hierarchical chains. These micro branches will determine the bottom/up testing sequence as a subroutine and then a module is completed. Test data will be defined by the programmer such that all processing branches of a module are excercised. The test results of these terminal routines will be hand verified for:
   o   arithmetic operations of formulas
   o   logical decisions
   o   internal program storage.

The testing procedure described is wholly consistent with the coding development scheme planned for EGEAS. Higher level coding will be constructed in skeleton form in parallel with the development of the detailed program units in order to facilitate interface accuracy. Testing will be performed concurrently with development. Since this testing will be done in parallel and in vertical branches, major portions of the system will be available for final testing prior to 100 percent completion of the project.

11.4 VALIDATION

Model validation will follow two paths. The first is an adaptation of work under way at MIT for EPRI in Model Assessment. The model assessment procedure at MIT includes the following procedural steps and/or levels of detail in the verification process:

o   Evaluation of Research Models and Issues;

o   Literature Review;

o   Self Audit;

o   Independent Model Audit;

o   Controlled Comparative Application; and

o   Third-Party Model Assessment.

This procedure has been developed primarily as a logical structure aimed at defining the steps toward third-party model assessment. For this reason the model validation process for EGEAS will proceed only as far as step three though with considerable attention to the ability of the modeling system to "predict prototype behavior." For this purpose, the first set of system-level tests will be based upon analyses of the EPRI synthetic utilities and a thorough analysis of model behavior compared against perceived or anticipated results from estimation of an expansion path from a small utility. Data bases for the EPRI synthetic utilities to be utilized in this component of the validation process are currently under development as a portion of the EGEAS project. The second set of system-level tests will be designed to assure that EGEAS can be used at any of a number of utility size scales. This will be a test for

dimensionality and will be accomplished by creating a synthetic utility much larger than that used in the majority of the testing but with identical generation characteristics and scaled present and future load.

The structure of EGEAS allows for one testing/validation procedure not available to other expansion models, the ability to test internal consistency between analysis alternatives. The EGEAS structure allows for five analysis options for analyzing expansion pathways. These are:

A. Prespecified expansion pathway
B. Year-end optimization
C. Linear programming
D. Dynamic programming
E. Generalized Benders' decomposition.

These five alternatives are different in at least the following characteristics:

A. Optimization, yes/no
B. Optimization linear/non-linear
C. Level of data detail
D. Ability to handle other analytic options such as weather-dependent generation sources.

Nonetheless, the basic core purpose of these expansion analysis alternatives is the same. For this reason, the solutions in which the analysis alternatives are run head to head would always be at least marginally different. The differences will be accounted for by differences in the algorithms used or through differences in basic assumptions associated with the use of the input data (the input data will be from a common data base and therefore within itself be consistent).

Appendix A

Lee, S., et al, "COMPARATIVE ANALYSIS OF GENERATION PLANNING MODELS

FOR APPLICATION TO REGIONAL POWER SYSTEM PLANNING

COMPARATIVE ANALYSIS OF GENERATION PLANNING MODELS
FOR APPLICATION TO REGIONAL POWER SYSTEM PLANNING

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INTRODUCTION

This paper reports the results of a study made by Systems Control, Inc. as a subcontractor of the University of Oklahoma, under the auspices of the Electric Energy Systems Division of the U.S. Department of Energy, to survey the state of the art in generation planning models and to assess their applicability to regional power system planning.

Study Objectives

The basic objectives of the study can be summarized below:

- Define the problems of generation planning for a regional power system.

- Survey the state-of-the-art models that are available to address these problems. Perform a comparative analysis of representative models.

- Recommend areas of research and development, if any, that are needed to perform regional generation planning.

Study Scope

In this study, emphasis is on models and methodologies that represent the state of the art rather than planning processes. In particular, by the words "models" and "methodologies", we mean mathematical procedures that are computer-based for the most part, with limited human interface. Since this definition still includes a large number of different models, we have further restricted the scope by examining only those models which address the generation investment problem directly in their formulation.

Generation planning, being part of the overall system planning of a power system which includes generation, transmission and distribution facilities, should ideally be solved with consideration of the interface with transmission and distribution planning. An attempt was made to combine generation and transmission planning in a single formulation (21). However, due to the complexity of the problem, it is unlikely to be both computationally feasible and sufficiently accurate. This approach will, therefore, not be considered in this paper. Included in the scope, however, will be the interface between the generation planning models and plant-site-related transmission investment.
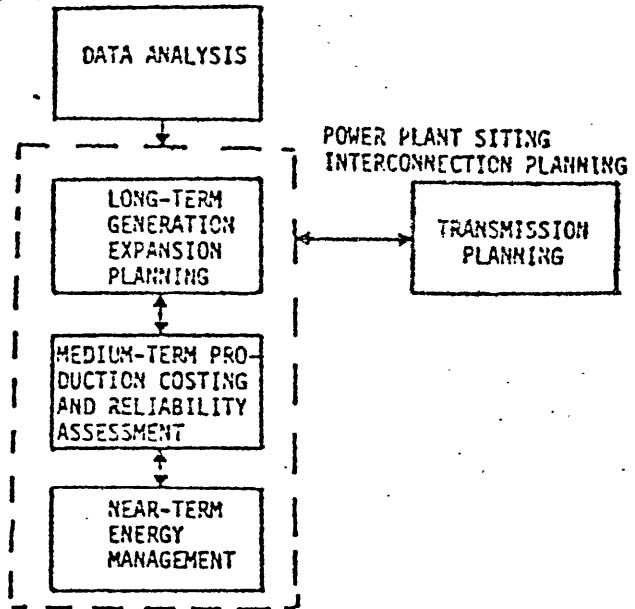
Fig. 1. Generation Planning Functions and Interface with Transmission Planning

Figure 1 shows the major functions of generation planning and the interface with transmission planning. The interface with transmission planning occurs in real life at all levels of planning and operation. For systems with strong internal transmission capability, most of the interaction is through power plant siting and the use of interconnection with neighboring systems as a means of reducing generation requirement. The interconnection option will not be included in the scope of this report.

Excluded from the scope also is the problem of near-term energy management which includes scheduling of maintenance and nuclear refueling and scheduling of seasonal hydro resources. Data analysis which provides load forecast, forced outage rates, hydro inflow data, etc. is likewise not considered. Corporate financial models which simulate the financial state of a utility for a given expansion plan are also excluded. Detailed production costing and reliability assessment models are not analyzed with the exception of the GRETA model of Electricité de France (EDF) which forms part of their overall planning package.

The criteria for model selection will be discussed in Section II. Six models were chosen for the comparative analysis. They are listed below:

● WASP - A dynamic programming model with probabilistic production costing developed by Jenkins and Joy.

● OPTGEN - A dynamic programming model with deterministic production costing developed by Lee.

● University of Massachusetts Model - A mixed integer linear programming model developed by Noonan and Giglio.

● MIT Model - An Economic-Environmental System Planning Package developed by the MIT Energy Laboratory.

● PUPS - A screening curve model developed by Lee and Dechamps which is capable of treating unconventional generation.

● MNI-GRETA - An optimal control model (MNI) and a Monte Carlo simulation model (GRETA) used by EDF.

In Section III, the models are evaluated according to the criteria of Section II. The comparison will proceed by criteria, so that the contrasts between features of various models are emphasized. Finally, in Section IV, the areas that require further research and development for the purpose of application to regional power system planning will be identified.

Each of the models are described in an appendix which is a synopsis of the available literature on the model. The appendices are organized under the following headings:

● Scope

● Objective

● Constraints

● Method of Solution

● Production Decisions

● Investment Decisions

● Limitations

● Examples and Test Cases

● Performance Capability

CRITERIA FOR MODEL SELECTION AND EVALUATION

An extensive literature survey on generation planning models was conducted before the final selection of six models was made. Both U.S. and European literature were searched. A bibliography is provided at the end of this paper. Because only a limited number of models can be evaluated and compared in this paper, a set of criteria was used in the selection process. They are listed below.

Criteria for Model Selection

● The model should be either proven in its practical application to actual power system planning or capable of solving real-life problems.

● The model should include features that represent the state of the art.

● The model should solve at least the investment and production costing problem of generation planning by an integrated computer package.

● There should be published literature and documentation available which describe the methodology in sufficient details to allow proper evaluation.

● The final set of models selected should present a reasonable spectrum of the different methodologies and capabilities of the state of the art.

The six models listed previously meet the above criteria. References to other models are found in Section V BIBLIOGRAPHY. Anderson (22) surveys the linear programming methodology which is used in the University of Massachusetts Model and the Westinghouse Model GENOP (see Day and Menge (24)). Another Linear Programming model similar in character to the MIT Model is one developed by Gordian Associates. Two models in addition to PUPS which use screening curves in static optimization procedures are OGP of General Electric (Garver, Stoll, Szczepanski (26)); and the model of the Central Electricity Generating Board of Great Britain (Phillips and Jenkin (28)).

Definition of Regional Generation Planning

The major objective of this study being assessment of the applicability of the models to regional generation planning, it is necessary to define the scope of regional generation planning for the purpose of establishing the criteria for model evaluation.

A region is taken to mean the service area of more than one contiguous electric utility. A strict interpretation of this definition should include the statement that there is more than one decision maker in finalizing the expansion plan, otherwise the

region would be equivalent to a single power company. When multiple decision makers from different utilities are involved, they will have their own objective of minimizing the cost of their own system, unless they have a coordination agreement whereby the objective of minimizing the total cost to the region overrides the individual objectives and a formula is used to share the costs and benefits on an equitable basis.

No generation planning methodology is available to address the regional planning problem with a multi-dimensional objective function, as would be the case involving multiple decision makers with different objectives. Because of lack of methodology, regional planning entities usually resort to one of two approaches:

(a) A single objective function with subsequent cost and benefit sharing, or

(b) Coordinated planning by individual utilities with various degrees of information exchange which may result in jointly-owned and jointly-operated generation facilities.

The latter approach is neither well defined nor well enough understood to allow either exact mathematical formulation or the development of planning models. It is therefore not a suitable definition of regional planning for the purpose of model evaluation. On the other hand, all generation planning models considered in this paper contain a single objective function and can be used in the former approach, even though they do not address the problem of cost and benefit sharing. Therefore, the following problem formulation for regional generation planning is adopted.

In regional generation planning, the objective function is to minimize the cost of generation investment and production to the customers in the region over a planning period, subject to reliability, environmental and financial considerations. The total costs and benefits of the resulting generation plan will be allocated on an equitable basis to the participating utilities comprising the region.

Criteria for Model Evaluation

The criteria for model evaluation can be grouped under five categories, namely, (1) Generation Alternatives, (2) Methodology, (3) Production Costing, (4) Problem Formulation, and (5) Computational Requirements. Each of the categories of criteria will now be described from the viewpoint of desirable characteristics for application to regional generation planning.

Generation Alternatives:

Generation alternatives are the options considered by the models in their optimization procedures for satisfying future expansion at minimum cost. For a single utility, a limited number of alternatives will suffice. For instance, within the class of nuclear units, one particular unit size may be sufficient to consider for an expansion period of ten years. However, for regional planning, each

participating utility may have its own optimal unit size. Coupled with other distinguishing features like different capital cost and fuel cost, a region may require a large number of generation alternatives.

In addition to the number of alternatives, the types of alternatives that can be considered by the models are also important. For some regions, hydro and pumped storage are not realistic options, however, they may form a major portion of the generation mix in other regions. The complete set of generation alternatives that are desirable for general application should include the following:

- Hydro

- Pumped storage and other advanced storages

- Thermal generation

- Unconventional generation

- Firm purchases

Methodology:

Under this general category, four criteria are included, namely,

- Method of solution

- Problem size

- Sensitivity analysis

- Availability of suboptimal plans

The method of solution refers to the mathematical technique used in solving the generation expansion optimization. Depending on the desired optimality, accuracy, and computational speed, several methods of solution are available. No single method has a distinct advantage over others for application to regional planning.

Problem size that can be handled by the models is an important consideration for regional planning. An inherent capability to perform problem size reduction is desirable. The ability of a model to provide sensitivity information or to permit efficient execution of sensitivity cases is very useful for planners. Of great value also is the availability of suboptimal plans which can provide a wider spectrum of candidate plans for final selection.

Production Costing:

The criteria under the category of production costing concern the modeling of important variables for estimation of production cost. They are listed as follows:

- Load representation

- Hydro and pumped storage modeling

- Treatment of unconventional generation

- Treatment of maintenance

Treatment of forced outages

Problem Formulation:

This category of criteria concerns the comprehensiveness of the problem formulation. They are designed to evaluate the factors that are either represented as constraints or part of the cost function for minimization. Considering the impact these factors may have on the resulting optimal plan, they share equal importance with the Methodology and Production Costing criteria. They are:

- Reliability
- Environmental effects
- Time horizon
- End effects adjustment
- Interface with transmission planning

Reliability and environmental effects may be modeled as constraints or part of the objective function. The time horizon that a model can handle may restrict its application to long-term regional planning. The end effects can influence the optimality of the expansion plan in several years before the terminal period. Since there exists a coupling between generation and transmission planning, for a globally optimal expansion, it is necessary to iterate between the generation and transmission plans. Therefore, a well-defined interface is desirable.

Computational Requirements:

Although future computer capability may be so unlimited that computational requirements are not an important consideration, in the near term, there are practical limits to the affordable computer resources that can be devoted to generation planning. For this reason, it should be considered as a criterion.

MODEL EVALUATION

In this section, the six models are evaluated and compared according to the criteria discussed previously. The most interesting comparisons are summarized in Table 1. The evaluation consists of delineating the capabilities, limitations and assumptions of each model and proceed by criteria.

None of the models is directly applicable to multiple utility regional planning problems although it may be possible to adapt them for this purpose. Assuming the problem size is manageable, the important issues become the question of the reliability of interconnected areas, cost allocation, and multi-area generation dispatch. Furthermore, the objective of regional planning is not necessarily the sum of total discounted costs for all utilities, due to complicated institutional factors and the inevitable issue of equitable sharing of costs and benefits over the geographically distributed service area.

Alternatives for Generation Expansion

All six models include the capability to automatically select a generation expansion plan from a set of alternative sources of generation. All models can handle thermal generating units as alternatives. That includes nuclear, coal, oil, gas and combustion turbines. The MIT Model also has the unique capability of characterizing the generation alternatives by thermal and air pollution abatement technology and their emissions.

With the exception of the MIT Model, hydro generation cannot be automatically selected by the models for generation expansion. The difficulty of this is due to the site-specific characterization of hydro units and site availability. The MIT Model incorporates a hydro site constraint.

Pumped storage hydro, being similar to regular hydro, is not included in all models as an alternative. The University of Massachusetts Model, WASP, and the MIT Model do, but OPTGEN, PUPS and the EDF Models do not. However, it should be noted that PUPS and the EDF Models permit the simulation of prespecified additions of pumped storage.

Unconventional generation sources like solar, wind, tidal power, etc. which are highly intermittent cannot be automatically included as an alternative for expansion in any existing model. PUPS was specifically designed to study the system benefits of an intermittent generation source like tidal power. It is, however, only a simulation model as far as the expansion of tidal power is concerned. Still, it allows important questions like energy credit and capacity credit to be answered.

For some utilities and for regional planning, firm purchases are often one of the economic options of meeting load growth. Firm purchase is a difficult alternative to model because of its dependence on the generation plans and demand forecasts of neighboring systems. Firm purchase is available only during those years when the neighboring system has excess reserve capacity, therefore, a firm purchase contract usually has a limited duration. This temporary nature of firm purchase distinguishes it from other generation alternatives. If the firm purchase is in the form of joint ownership with a fixed percentage of capacity, it may be approximately treated as a regular generation alternative. If it is a utilization of the neighbor's surplus capacity then none of the six models can consider it as an expansion alternative.

Methodology

The models are compared under the sub-headings of Method of Solution, Problem Size, Sensitivity Analysis, and Suboptimal Plans.

Method of Solution:

The objective functions(sum of operating and investment costs) for the University of Massachusetts and MIT Models are similar. They are both linear in the number of capacity installations by type, vintage, and time. Mixed integer linear programming and

Table 1. Comparison of Generation Planning Models

MODEL / CRITERION	U. Mich.	WASP	OGP/LM	MIT	PGP	PUPS
Generation Alternatives Available						
Hydro	No	No	No	Yes	No	No
Storage	Yes	Yes	No	Yes	No	No
Thermal	Yes	Yes	Yes	Yes	Yes	Yes
Unconventional	No	No	No	No	No	No
Purchases	No	No	No	No	No	No
Methodology						
Solution Method	Mixed Integer Linear Programming	Forward Dynamic Programming	Forward&Backward Dynamic Programming	Linear Programming	Steepest Descent applied to Max. Principle	Screening Curves
Problem Size	Limited	Limited	Limited	Limited	Limited	Unlimited
Sensitivity Analysis	Yes	No	No	Yes	Yes	No
# of Suboptimal Plans Available	0	10	100	0	0	0
Production Costing						
Load Representation	Load Duration Curve	Load Duration Curve	Peak & Total Energy Demand	Load Duration Curve	Load Duration Curve	Hourly Load Data
Modeling of Hydro	Yes	Yes	No	Yes	Yes	Yes
Modeling of Storage	Yes	Yes	No	Yes	Yes	Yes
Provision for Unconventional Sources	No	No	No	No	No	Yes
Treatment of Maintenance	Derate	Heuristic	Derate	Mixed Integer Linear Programming	Optimize	Derate
Treatment of Forced Outages	Derate	Equiv.Load Duration Curve	Derate	Equiv.Load Duration Curve	Monte-Carlo Simulation	Derate
Problem Formulation						
Reliability Treatment	Approx. Distribution	Equiv.Load Duration Curve	Approx. Distribution	Reserve Margin	Penalty Cost	Equiv. Load Duration Curve
Environmental Effects	No	No	No	Yes	No	No
Length of Planning Horizon (yrs.)	10-20	10-30	10-20	10-20	10-20	10-50
Accounting for End Effects	Extend Evaluation Period	None	Adjust Capacity and Extend Period	None	None	Extend Evaluation Period
Transmission Planning Interface	None	None	Select Plant Sites with Transmission Costs	None	None	None
Computational Burden	Moderate	High	Moderate	Moderate to High	High	Low

Bender's decomposition principle are applied to the University of Massachusetts Program, taking into account the separable operating and investment decisions. MPSX (Mathematical Programming System Extended) is used by the MIT Model to perform the revised Simplex Method on the linear program whose coefficients are provided by a simulation program.

Dynamic Programming (DP) is employed in the WASP and OPTGEN packages. WASP uses forward DP while OPTGEN uses both forward and backward DP. In forward dynamic programming, each feasible generation expansion configuration at each stage is identified with a sequence of unit capacity additions which yields the minimum cumulative expansion cost up to that stage. OPTGEN affords the opportunity to explore suboptimal plans by the use of backward dynamic programming. Associated with each configuration at each stage is a sequence with the minimum cumulative cost of expansion that will be incurred from this state until the end of the expansion period.

Nonlinear programming is applied to the Optimal Control Problem formulated in the EDF Model. The nonlinear function of the configuration (operating cost) is provided by the simulated production cost.

PUPS uses a static optimization procedure involving production cost simulation, screening curves and existing generation mix to determine capacity additions required.

Problem Size:

Due to the large number of production cost simulations involved in dynamic programming, the number of possible generation expansion configurations in any year is limited to 200 in the case of WASP and a truncation algorithm is used in OPTGEN to eliminate plans which are costly in the interim between the initial and final periods of the study. In this latter case, the maximum number of states for any year is 200 and the number of generation alternatives can not be more than 5. Limitations in scope of all the models except PUPS are due to their dynamic nature and the geometric growth in computation as states or stages increase.

Sensitivity Analysis:

A useful feature for power system planners is the sensitivity information provided by the dual variables in the models solved by linear programming. Thus, for example, in the MIT Model, the effect on the cost of providing electricity of the constraints on the number of plant sites corresponding to capacity size can be determined.

The EDF MNI Model computes the co-state variable of the optimal control problem which can be interpreted as the "value of use" of a certain equipment addition. It is in fact the sensitivity of the total system cost to the incremental change in that equipment capacity.

The University of Massachusetts Model can be rerun starting from a base case solution to answer the "what-if" type of sensitivity analysis while

using only 20 to 40 percent of the normal computer time to solve a base case.

OPTGEN can be executed in a simulation mode in which the optimal plan or any specified plan can be simulated without solving the optimization problem. This permits repeated runs of the program for sensitivity information and must be rerun for a change of parameter.

Suboptimal Plans:

Corresponding to the sensitivity feature of linear programming is the feature of the dynamic programming models (OPTGEN and WASP) that allows direct output suboptimal plans without additional computation since the simulation for these cases is already performed in the optimizing process. There is a difference in the approach of WASP and OPTGEN in deriving the suboptimal plans. WASP computes the n-best (up to 10) alternative expansion paths up to a given generation configuration during the forward DP. At the end, the true n-best plans are derived. However, in practice, these 10 best plans are nearly identical to one another except for small deviations, mostly in the last few years of the expansion period. The value of these suboptimal plans is therefore questionable.

OPTGEN does not generate the true 100 consecutive best plans. However, by combining forward and backward DP, it can generate a vast number of plans which are made up of suboptimal trajectories. These plans are simply sorted in order of their costs to provide the 100 best plans. An algorithm is also available to discard plans that are similar with the exception of differences occurring in a specified number of ending years. Results show that these plans exhibit a much wider range of generation mix.

Production Costing

The methodologies of the models in production costing are compared under the topics of load representation, hydro and pumped storage modeling, modeling of unconventional generation, maintenance scheduling, treatment of forced outages, and cost computation.

Load Representation:

A majority of the six generation planning models use load duration curves in the production cost simulation. WASP represents the curve as a 5th order polynomial while the University of Massachusetts Model treats it in a linear programming fashion; the duration parameter specifies the number of hours load demand is above a certain level. The EDF MNI Model also uses a discrete load duration curve with 10 levels corresponding to well-known periods of the day. OPTGEN uses a trapezoidal approximation of the generation duration curve based on the specification of peak and total yearly electric energy demand.

PUPS performs the simulation of non-thermal generation dispatch, i.e., hydro, pumped storage and unconventional generation, on the hourly load data

over an entire year. The resulting thermal load is converted to an annual load duration for production costing.

Hydro and Pumped Storage Modeling:

Two of the models (University of Massachusetts and MIT) treat hydroelectric and pumped storage plants in a similar manner. The constraint set of the linear program includes the demand placed on the system by pumping in addition to consumer load demand. Both model the storage plant by an efficiency parameter. The University of Massachusetts Model includes a constraint which ensures water levels are returned to the same level at the end of the period with which they began. Siting constraints are included in the MIT Model so that the total capacity of hydro plants in specific locations is limited by water flow, temperature, surface discharge, and loading standards.

PUPS uses the weekly load duration curve for simulation as the peak is shaved by hydro energy. An iterative approach to the determination of the pumped storage charging schedule is found by valley filling subject to energy storage capacity constraints. At the end, hourly schedules are derived.

All hydro units must be combined into a single unit in the WASP and the EDF MNI Models. WASP affords the capability of dividing capacity into two blocks for base loading and peak shaving; in addition an emergency category may be defined allowing for units out of service to be backed up by hydroelectric plants. The more detailed GRETA Model of EDF represents the hydro system by three equivalent units (seasonal, weekly, and run-of-the-river) and allocates energy differently in each case. Pumped storage, aggregated into weekly and daily cycle units are scheduled by a linear programming iterative suboptimization.

Modeling of Unconventional Generation:

PUPS provides the only model in which unconventional electric generation can be treated. Either an unconventional source may be used to supply load just above the must-run generation or storage devices can be employed for retiming. Another important feature is the capability of selling residual unconventional generation in a secondary market, such as to another power system. Although the model was specifically developed for tidal power, any intermittent generation sources can be simulated, provided an annual sample of hourly generation output can be specified.

Maintenance Scheduling:

Derating is the simplest way of modeling maintenance requirements for production costing. The capacity is effectively reduced by the fractional amount of maintenance required, but no account is taken of strategic policies which enable other units to cover the outages in an optimal manner. OPTGEN and PUPS use this derate capacity in the stacking of units under the load duration curve, while the capacity as derated appears in the constraint set of the University of Massachusetts Model.

WASP classifies generating units by their capacity magnitude to limit the number of scheduling variables. The equivalent maintenance blocks are scheduled in the sequence of decreasing size, each time fitting a maintenance block to the period of greatest remaining reserve.

Both the MIT production cost model and the EDF MNI Model feature optimized maintenance scheduling; where, in the latter case, the maintenance scheduling variables are included in the set of decision variables and, in the former case, shutdown can be accomplished for either economic or environmental reasons. In the EDF GRETA Model, because it is a Monte Carlo simulation, the maintenance schedule is prespecified input data.

Treatment of Forced Outages:

As in the case of maintenance scheduling, derating is a popular method of accounting for losses of generating capacity due to unplanned outages. PUPS, University of Massachusetts and OPTGEN use this approach. Actually, this possibility is a random variable which is conveniently represented as a Bernoulli process in an approach referred to as the equivalent load duration curve method. Both the WASP and MIT Models use this approach. Monte Carlo simulation is used by the GRETA Model where samples of available thermal capacities are drawn using the Markovian assumptions.

Cost Computation:

Of the models surveyed, three use annual fixed charges to compute the capital cost. OPTGEN, PUPS and EDF use this approach. The University of Massachusetts, MIT and WASP models are similar in that they represent investment cost by a single cash outlay at the initial period when the plant goes on line. Institutional factors accounting for preference between domestic and foreign capital are modeled by a weighting coefficient in WASP.

Problem Formulation

Under this category of criteria, the models will be evaluated according to their ways of treating reliability, environmental effects, time horizon for the planning period, adjustment of results to account for end effects and their interface with transmission planning.

Reliability:

Two popular approaches to characterize reliability are:

(a) Reserve margin and

(b) Equivalent load duration curve.

As a byproduct of the production simulation using the equivalent load duration curve (ELDC), the Loss-of-Load Probability (LOLP) and expected unserved energy may be computed. In the case of WASP, these may then be applied to restrict the state space. OPTGEN approximates the cumulative distribution of forced outages by four log-linear segments and

computes the LOLP. MIT uses a reserve margin para-
meter in the constraint set to determine the amount
of over-supply. EDF models failures as a cost which
is added to the operating and investment costs in
the objective function. The University of
Massachusetts Model uses an analytical approximation
of the reliability function based on the mean and
variance of the total available capacity, similar
to the OPTGEN approach.

Environmental Effects:

The effect on the environment is considered
only by the MIT Model. Fuel availability, site-
capacity restrictions, new unit addition rate,
stack emissions, air quality, river flows, tempera-
tures, lake loading and surface discharge are limited
by the constraints in the model. More detailed
modeling over a limited time period is provided in a
nonoptimizing production model.

Time Horizon:

A practical-upper bound for the time horizon for
all models but the static PUPS is about 10 years
since computation time increases geometrically with
the study period length for these models. Computa-
tion time is linear in the length of study period
for PUPS and the study is limited only by uncertain-
ties about future demands and prices. Fifty years
is a reasonable upper bound in that case. If one
accepts time steps of more than one year, the EDF
MNI Model can solve for a longer expansion period.
Likewise, the expansion period may be up to 30 years
using WASP if one accepts the possibility of deri-
ving only a suboptimal plan by means of arbitrarily
reducing the state space for the dynamic programming.
Another artifice is that of decomposing the expan-
sion period into overlapping sub-periods and solve
for each period sequentially with coupling through
the initial conditions, as was demonstrated by an
application of the University of Massachusetts Model.
Again, optimality is not guaranteed in this case.

End Effects Adjustment:

End effects in a model account for differences
in capacity of alternative plans at the terminal
point of the study period. One way of considering
these is to artificially extend the planning period
by a number of years called the evaluation period
in which the system is in steady state, i.e., no
increases in aggregate demand or changes in the
generation system. The length of this extension is
an input parameter in PUPS, whereas it is equal to
the maximum immature period of all generation alter-
natives in the case of the University of Massachu-
setts Model. The OPTGEN package also allows for the
fixed costs for units in the terminal year to be
prorated according to the adjusted capacity which
will result in a specified LOLP level. The adjusted
cost of the terminal year is then projected for the
evaluation period and added to the objective func-
tion for optimization. WASP, the MIT Model and the
EDF Model do not account for end effects.

Interface with Transmission Planning:

OPTGEN is the only model that provides an

interface with transmission planning by modeling the
site-related transmission cost. A site is charac-
terized by a staircase cost curve which relates
transmission cost to generation capacity at the site.
In the forward dynamic programming step, new gene-
rating units are automatically assigned to sites
where the incremental transmission cost is least.
Transmission fixed charges are added to the operating
and investment costs of the expansion plans. This
approach is a suboptimization which does not account
for dynamic effects and it requires the pre-speci-
fication of site-related transmission costs.

Computation Requirements

.Many models require the use of a number of sub-
models serving various functions. When operated in
a modular fashion, analysis may be cumbersome and
time-consuming. Separate models to define unit
types, describe the load duration curve, configure
the expansion plan, simulate the system and optimize
the plan are required for WASP. Similarly, the EDF
package requires the use of an intensive production
costing simulation to check the optimizing program
after a plan has been determined. The integrated
MIT Model consists of two iterative sections - one
uses operating data to optimize the configuration
and the other finds the optimal operating strategy
given the configuration. A detailed production cost
model is also included. The large linear program-
ming problem in the University of Massachusetts
Model is subdivided and solved iteratively. PUPS
features sequential rather than iterative operation
of its subprograms with a consequent decrease in
user-imposed burdens. Core storage requirements for
WASP, PUPS and OPTGEN are at least (30-60K words)
while the University of Massachusetts requires some-
what more (100K words). A source of difficulty may
be the presence of round-off errors which arise in
linear programming as in the University of Massachu-
setts Model and the MIT Model. This problem may also
arise in the solution of the optimal control problem
in the MNI Model of EDF.

Since computational requirements are difficult
to compare without resorting to benchmark studies,
a qualitative comparison is made. WASP and the
EDF models require the highest computational burden.
Next comes the MIT Model, followed by approximately
equal computational requirement by the University
of Massachusetts Model and OPTGEN. PUPS requires
the least computation.

RECOMMENDATIONS FOR RESEARCH

Based on the survey and the comparative analysis of six generation planning models, certain deficiencies of the state of the art as applied to regional generation planning have emerged. They are classified into near term and long term research areas and described below. Those labeled near term should require less mathematical development and less computational breakthrough than those classified as long term. Since the relative importance of these research topics are somewhat subjective, the order in which they appear below does not reflect any ranking.

Near Term Research Areas

(1) Comprehensive Expansion Alternatives: With the increasing interest in unconventional generation resources like solar and wind power, and also in load management which includes customer load management as well as supply management, a larger number of alternatives for satisfying expanding electricity demand will have to be considered, especially for regional generation planning which may encompass a service area larger than that of a single utility. Future research should consider the modeling of these emerging resource options in the context of generation planning and develop more powerful optimization methods.

(2) Problem Size Reduction: In the near term, before more powerful computers or mathematical techniques are available, it will be necessary to reduce the problem size by means of equivalent representation, space or time decomposition, etc. for present methodologies to be practical for regional applications.

(3) Cost and Benefit Allocation: In real life, cost and benefit sharing is practiced by the utilities that coordinate their planning. However, these practices should be reflected in the generation planning models to facilitate the process and to allow individual participants to know their own cost and benefit readily.

(4) Planning Under Uncertainty: The state of the art in generation planning already includes modeling the uncertainty of generation outages, hydro inflows and load. Other factors like construction delay, major disruptions of fuel supply, etc. are not yet incorporated in existing models for automatic generation expansion. In terms of their consequences, these uncertainties could be equally or more important than those already modeled.

Long Term Research Areas

(1) Integration With Transmission Planning: Combined generation and transmission planning would be a very useful technique if it is practical and sufficiently accurate. It would then eliminate the necessity of manual iterations between the two planning processes and would provide assurance of an optimal expansion plan for both.

(2) Integration With Regional Energy Model: At the present, generation planning is an open-loop process. The effect of the cost of electricity on the load forecast is not considered. In addition, the cost of fuel is considered to be given and unaffected by the region's fuel consumption, a major part of which is for electric generation. To complete the loop, the generation planning model should be integrated with a regional energy model which should contain a load forecasting module.

(3) Generation Planning With Multiple Objectives: The MIT Model considers the environmental-economic trade-off for generation planning. It is one step towards developing methods for planning with multiple objectives. In the case of regional planning involving multiple decision makers, it may be necessary to take this approach. Recent mathematical developments in game theory and fuzzy sets may be applicable.

(4) Extension of Objective Function to Include Social Costs: If the regional planning entity is mandated to optimize the social costs, it would be necessary to consider them in the objective function. The approach of including a cost of unserviced energy by EDF is one step in that direction. But other costs, such as employment, taxation, etc. should also be considered.

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APPENDIX A
WASP - WIEN AUTOMATIC SYSTEM PLANNING PACKAGE

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Scope

WASP is designed to find the optimal generation expansion policy for an electric utility system using dynamic programming and probabilistic simulation. The program evolved from the SAGE expansion program at the Tennessee Valley Authority.

Featured in the planning package are the following capabilities:

- User supplied life of new generation projects

- Pumped storage and hydroelectric

- Probabilistic simulation including forced outages and scheduled maintenance

- Binding constraints

- Separation of financial calculations into domestic and foreign accounts

- Study period of up to 30 years in length

- Modular configuration allows flexible data manipulation

Objective

The objective function is the present worth discounted summation of capital costs, operating costs and salvage value. For capital expenditures, the escalation rate of construction cost and discount rate of time preference can be combined in the formula

$$Q_{kj} = \frac{(1 + m_k)^p}{(1 + i_k)^n}$$

where Q_{kj} = Combined present worth and escalation factor for expansion unit k in study year j

m_k = Escalation rate of kth candidate

i_k = Present worth discount rate for k^{th} candidate

n = Number of years from present-worth base year

p = Number of years from escalation base year

In the case of a new unit, the capital cost is considered to be paid at the initial point of a specific stage (or year) as is the capacity increase. A "weighting factor" to reflect preferences with regard to foreign capital is included in the capital expenditure calculation.

$$C_j = \sum_k \left[QL_{kj} \cdot IL_k + FF_j \cdot QF_{kj} \cdot IF_k \right]$$
$$\cdot MWC_k \cdot N_k \cdot 10^3$$

C_j = Present worth of capital expenditure for year j

k_j = Index number of expansion unit

QL_{kj} = Local capital present-worth and escalation factor

QF_{kj} = Foreign capital present-worth and escalation factor

IL_k = Base year local capital cost

IF_k = Base year foreign capital cost

FF_j = Foreign capital "weighting factor"

MWC_k = Megawatt capacity of kth expansion candidate

N_k = Number of units added of type k

Credit to the objective function from salvage value is represented by the discounted residual capital expenditure

$$R_j = \sum_k P_{knyr} S_{kj}$$

where R_j = Credit for all unit additions in year j

P_{knyr} = $(1+i_k)^{-nyr}$

nyr = Number of years from P.W. base year to end of study

S_{kj} = Computed salvage value for unit(s) k. (see below)

If C_{kj} = Undiscounted capital cost for expansion candidate k escalated to year j,

then $C_{kj} = \left[(1+m_k)^p IL_k + FF_j(1+m_k)^p IF_k \right]$
$\cdot MWC_k \cdot N_k \cdot 10^3$

and $S_{kj} = \left[1 - \frac{y_k}{L_k} \right] C_{kj}$ (Straight Line Depreciation)

where L_k = Economic life in years of candidate

y_k = Study life portion of economic life

or $S_{kj} = \left[1 - \frac{1 - (1+i_k)^{-L_k + y_k}}{1 - (1+i_k)^{-L_k}} \right] C_{kj}$

(Sinking Fund Depreciation).

Operating costs due to fuel expenditures are assumed to be paid at the mid point of each stage. Then the combined present-worth and escalation cost factor for fuel ℓ in year j is:

$$Q_{\ell j} = \frac{(1+m_\ell)^n}{(1+i_\ell)^{m+\frac{1}{2}}} \, .$$

Hence operating cost for year j is

$$Q_j = \sum_\ell Q_{\ell j}(CST_\ell + NFCST_\ell) + QF_{\ell j}$$

$$\cdot \; EF_j \cdot FCST_\ell$$

where CST_ℓ = Local fuel expenditure for fuel type ℓ (See Production Decisions)

$FCST_\ell$ = Foreign fuel expenditure

$NFCST_\ell$ = Local nonfuel operating expenditures

Finally the complete objective is

$$L(X) = \sum_{j=1}^{t} C_j - R_j + Q_j \, .$$

Constraints

Constraints in dynamic programming have a non-pejorative effect and actually make computation time feasible. A particular state configuration must have a minimum and maximum reserve requirement; a greatly expanded system is not economic. Thus

$$SCAP \geq \left(1.0 + (RSV)_{min}\right) \cdot MWPEAK$$

$$SCAP \leq \left(1.0 + (RSV)_{max}\right) \cdot MWPEAK$$

where $SCAP$ = Capacity of state (MW)

$(RSV)_{min}$ = Minimum reserve margin

$(RSV)_{max}$ = Maximum reserve margin

Another means of reducing the number of alternatives is to place a restriction on the number of units for each project considered, then

$$(MIN)_i \leq N_i \leq MAX_i$$

where $(MIN)_i$ = Minimum number of units to be considered

N_i = Number of units of expansion candidate i

$(MAX)_i$ = Maximum number of units to be considered

Additionally, the actual reliability of the generating system is computed in the simulation subprogram and states which do not meet the critical value are rejected. User-controlled constraints on state capacity and alternative selection may be modified without concomitant loss of state simulation data when it is found that the constraint is binding for the optimal solution.

Method of Solution

The WASP package is composed of six program modules; each is executed separately and data may be checked and corrected before implementing the next step.

The Fixed System Program (FIXSYS) describes the state of the initial existing power system and includes data on the number of units of each type, minimum and maximum operating capacities, heat rates, fuel type and cost, forced-outage rates and maintenance requirements. Precommitted units and retirement rates are also specified.

VARSYS (The Variable System Program) defines the unit types to be considered in expansion plans. This may include pumped storage and/or hydroelectric projects. Data requirements correspond to the inputs of FIXSYS.

Generation requirements in each stage of the study are defined by the Load Description Program (LOADSY) which develops the load duration curve for each period within the year from the load data.

The Expansion Configuration Generator Program (CONGEN) allows the system planner to direct the focus of this study to the area of most economic concern by user-controlled constraints (see Constraints).

Simulation of the configuration and computation of the operating cost is provided by MERSIM (Merge and Simulate Program). A probabilistic model is used to calculate unit loadings, system cost (in local and foreign exchange), probability of not being able to meet the system load and the probable amount of unserved energy.

The optimal expansion policy and economic calculation of fuel escalation prices, penalty on foreign expenditures and present-worth is determined by the Optimization Program (DYNPRO). States which are feasible are those which have a lower LOLP than the critical value. Constraints used in CONGEN to expedite the procedure which are binding in the optimal solution are identified by DYNPRO.
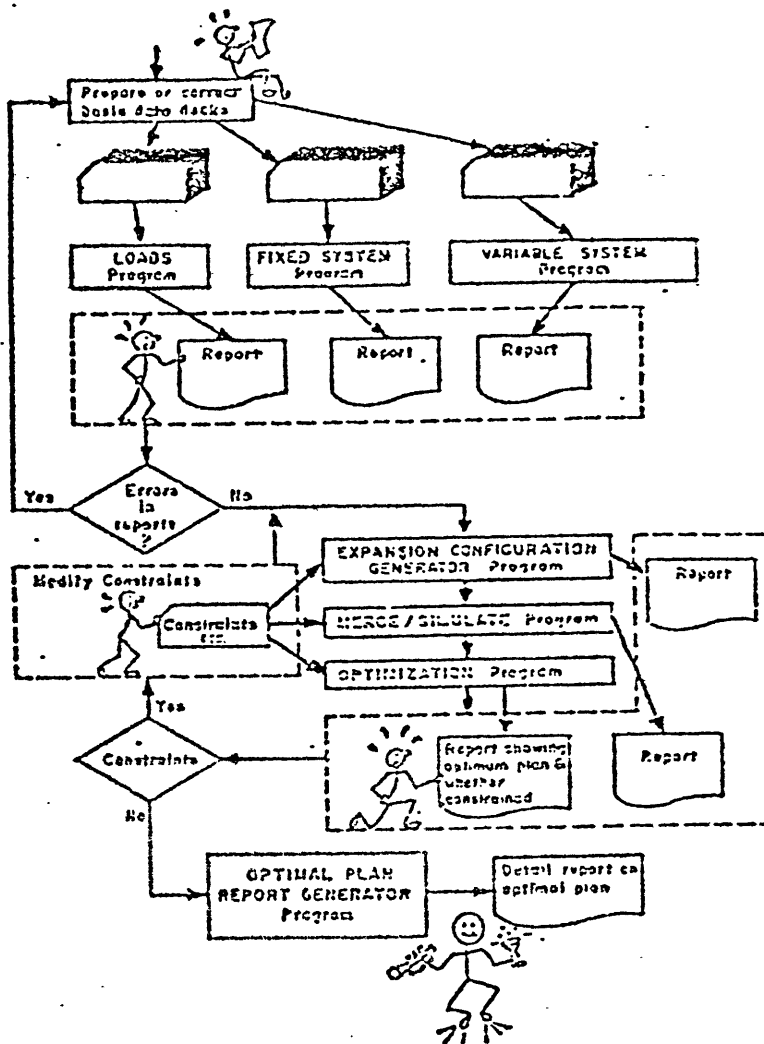
Production Decisions

The shape of the load duration curve is represented as a fifth order polynomial

$$y = \sum_{j=0}^{5} a_j x^j$$

where y = fraction of peak load

x = fraction of time

The coefficients $(a_o, \ldots, a_s)$ determine the shape and must be modified if a change in shape is forecasted. Peak loads are specified for each stage in the study period; fractions of the annual peak are input. Then the year is subdivided into periods (at most 12). For use by the simulation program, the curve is discretized into a partition with mesh DM. The following must hold:

$$DM > \frac{(ICAP)_{max}}{590}$$

where $(ICAP)_{max}$ is the maximum installed capacity. The number of points in the partition may be estimated by:

$$N = \frac{ICAP}{DM}$$

In practice 100-350 discrete points are recommended.

Prior to production costing and simulation an estimated maintenance schedule must be formulated to determine equipment availability. The procedure outlined here classifies generation units by capacity magnitude and allocates time for maintenance for the largest class when reserves are greatest and correspondingly for the smallest class when reserves are least. The minimum reserve for each period:

$$MNRSV_i = INSTCP_i - MAXLD_i$$

where $MNRSV_i$ = Minimum reserve in period i

$INSTCP_i$ = Installed capacity in period i

$MAXLD_i$ = Maximum system load in period i

If $PSMAIN_i$ is the previously scheduled maintenance in period i then available maintenance space for that period $MAINSP_i$ = $MNRSV_i$ - $PSMAIN_i$.

Each class has total maintenance requirement

$$MWDAYS = \sum_i (MWC)_i \cdot (MAINT)_i$$

$$\cdot (NOSETS)_i$$

where $(MWC)_i$ = Actual capacity of unit i

$(MAINT)_i$ = Maintenance requirement for unit i

$(NOSETS)_i$ = Number of units i

The amount of maintenance that can be performed by removal of a specific capacity for the entire period (maintenance block)

$MAINBK$ = $(MAINCL) \cdot (T_p)$.

$MAINCL$ = Capacity of maintenance class

T_p = Length of period in days

$NO = \frac{MWDAYS}{MAINBK}$ blocks are required for each main-
tenance class and the blocks are sequentially as-
signed to this period with the largest maintenance
space ($MAINSP_i$). Each class is considered in order
starting with the one of greatest magnitude.

An example is pictured in the accompanying diagram in which the first two maintenance blocks were scheduled during the first period, the third block to the second period and the remaining frac-tional block to the fourth period. This illustrates consideration of a fractional block where an esti-mated interpolated capacity $MCLL$ = $\frac{REMAIN}{T_p}$ allows the maintenance to extend over the entire period.

$REMAIN$ = $MWDAYS - \lfloor NO \rfloor \cdot MAINBK.$
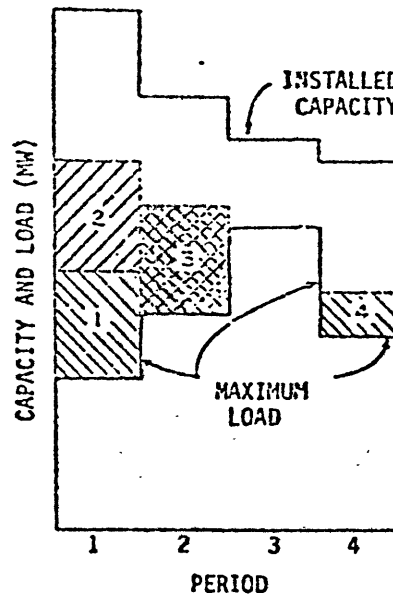
PERIOD

Once all the classes have been provided with maintenance schedules the availability rate for each unit is calculated as follows:

$$P_i = \frac{N_i}{NO}$$

P_i = Probability of performing mainte-nance for class in period i

N_i = Number of maintenance blocks sche-duled in period i

Thus expected outage rate

$$(Pm)_i = \frac{(MAINT)_i \cdot P_i}{T_p}$$

whereupon the expected availability rate for each unit

$$A_i = (1 - Pm_i)(1 - FOR).$$

Simulation of the effect of random outages is expressed by means of the equivalent load duration curve for each period:

$$EL_i(\cdot) = P_i\, EL_{i-1}(\cdot) + q_i\, EL_{i-1}(\cdot - MW_i)$$

where $P_i + q_i = 1$

P_i = Availability rate for unit i during period (see above)

and EL_o = Original load duration curve

Expected generation for unit i is

$$E_i = P_i \, T \int_{\sum_{j=1}^{i-1} MW_j}^{\sum_{j=1}^{i} MW_j} EL_{i-1}(x) \, dx.$$

the LOLP is P^* and expected unserved energy

$$U = T \int_{\sum_{j=1}^{i} MW_j}^{\infty} EL_i(x) \, dx.$$

in the following diagram:

In the previous discussion, it was assumed that units would be completely loaded in turn; a more realistic assumption is that the loading is divided into base load and peak load blocks. Generally, base load and cycling units are defined with two blocks and peaking units only have a load following component. A heat rate is specified for the base block as is the average incremental heat rate for the load following block.
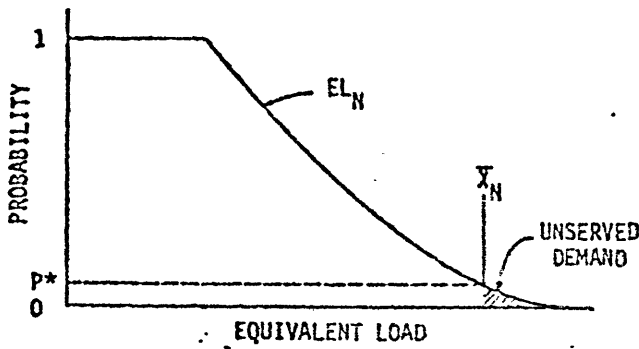
Hydroelectric projects must be combined into a single unit whose capacity is the sum of each individual unit capacity as is the energy of the entire project. As in the thermal units, capacity can be divided into two blocks; the base block is placed in first position in the loading order and the residual capacity is used for peak shaving. Energy generation is limited by water supply and reservoir constraints. In addition, an emergency hydroelectric category may be defined. This is used to increase system reliability by "backing up" units out-of-service. A penalty cost is associated with this type of operation. Capacity multipliers are defined to reflect varying distribution of energy and capacity availability among periods within the year.

As in the case with hydroelectric generation,

the capacities and reservoir limits are combined for all pumped-storage units to yield a combined unit. The cycle efficiency is the weighted average of the individual efficiencies.

Plant types are indexed by five types:

Nuclear

Fossil-fired

Hydroelectric

Pumped-storage

Emergency hydroelectric

Moreover, the fossil-fueled plant can be divided into four subgroups with their own unique fuel requirements.

Costs are obtained from the heat rates:

FLHTRT $= \dfrac{(BHRT)(MWB) + (CRMHRT)(MWC - MWB)}{MWC}$

BHRT $=$ Heat rate for base block

MWB $=$ Capacity for base block

CRMHRT $=$ Average, incremental heat rate for load following portion

FLHTRT $=$ Full load heat rate

Then operating cost for fuel,

OC $= 10^{-5} \, (HR) \, (FC)$

HR $=$ Appropriate heat rate

FC $=$ Appropriate fuel cost

(can be calculated for foreign or local expenditure).

Non fuel expenditure for each unit is

$$NFCST = OMA \left(\frac{12}{NPER} \right) \cdot MNC \cdot NOSETS \cdot 10^3$$
$$+ \, OMB \cdot (ENGB + ENGP)$$
$$\cdot 10^3$$

where NFCST $=$ Non fuel expenditure for unit operation

OMA $=$ Fixed O & M cost

NPER $=$ Number of periods in year

NOSETS $=$ Number of identical units

OMB $=$ Variable operating and maintenance cost

ENGB $=$ Expected generation of base portion of capacity

ENGP = Expected generation of peak portion of capacity

Investment Decisions

The optimization procedure (dynamic programming) finds the policy which results in a system of desired reliability with minimum discounted cash flow expenditures over the study period.

Let $D(t)$ = Decision made between stage t-1 and stage t

       $X(t)$ = State or configuration of power system

then $X(t) = X(t-1) + D(t)$.

implies $X(t) = X(0) + \sum_{j=1}^{t} D(j)$ where $X(0)$ is the

the initial system state.

The objective function is

$$L(X) = \sum_{j=1}^{t} C_j - R_j + O_j \quad \text{(see Objective)}$$

To find the optimal path, the optimal path to every state in each stage is determined up to stage j-1 by the recursive procedure outlined here. The optimal objective costs to states at stage j-1 are added to the cost of attaining the state under consideration at stage j to find that state in stage j-1 that lies in the optimal trajectory to the state at stage j. Associated with that state in the final year of the study period which has the minimum cumulative discounted cost is the optimal trajectory which can be determined by tracing backward to the initial condition.
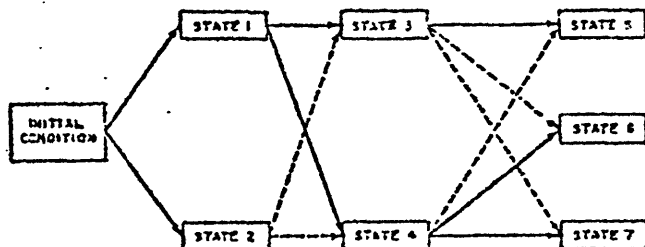
Limitations

In the approximation of capacity required for a fractional maintenance block, a distortion of actual capacity removed from the system is incurred. The number of maintenance classes should not exceed 7 for this reason.

Uncertainty is neglected in the load forecast and hydroelectric capacity. Also, the ability of hydroelectric power to cover forced outages is neglected in the model due to the removal of the peaking portion of the hydroelectric energy directly from the original load duration curve. The maximum

number of configurations in the Optimization Program is limited to 200 requiring the use of restrictive user imposed "tunnels" that often sharply restrict global optimality to a local region and require heuristic methods of constraint modification. The length of the study period is limited to 30 years.

Examples and Test Cases

Not available.

Performance Capability

Maximum core storage required for the WASP package is 30 K words and 120 K bytes on an IBM computer. Data may be used from previous iterations to facilitate computation time reduction.

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APPENDIX B

**OPTGEN - OPTIMAL GENERATION EXPANSION
BY DYNAMIC PROGRAMMING**

</div>

Stephen T. Lee   Stone and Webster
                      Engineering Corporation

Scope

This program determines optimal generation expansion plans for an electric utility using dynamic programming. It has the following special features:

● Automatic computation of up to 100 near-optimal expansion plans

● Manually prepared expansion plans can be simulated using the same program to provide a consistent evaluation and comparison with the program-generated optimal plan

● Automatic selection of plant sites with their associated transmission costs

● Option to use probabilistic or deterministic production cost simulation

● Automatic truncation of non-optimal plans

● Capacity and cost adjustments to account for end effects of alternative plans

Objective

The normal practice by a privately-owned utility company in generation expansion planning is to minimize the present worth of the revenue requirement. Included in the revenue requirement is the rate of return allowed by a regulatory agency.

The objective of the program is to minimize the present worth of the annual revenue requirement over a selected period. Two periods for defining the objective function are allowed:

(1) Simulation period only, i.e., only those years in which actual load growth and unit additions are simulated.

(2) Simulation period plus an evaluation period of any duration. In the evaluation period, load

growth is assumed to be stopped and genera-
ting units are replaced in kind.

Revenue requirement consists of fuel costs, O&M
costs, depreciation, interest payment, insurance,
taxes (if any), and return on equity. A levelized
fixed charge rate is used to represent the equivalent
uniform annual cost of owning a particular facility.
Fixed charges include those for generating facili-
ties as well as for site-related transmission faci-
lities.

Escalation rates can be specified for capital
investment (one rate for all types), separately for
three fuel types, and for all operating costs.

Only one discount rate for present worth calcu-
lation is allowed and it cannot be time-varying.

Constraints

The following constraints are considered by the
program to limit the number of feasible states.

Reserve Constraints:

The reserve constraints used in the program de-
fine a minimum and a maximum percentage reserve with-
in which feasible expansion plans are sought.

Reliability Constraint:

A reliability index is calculated for each po-
tential state of expansion and a minimum reliability
index based on the benchmark year performance is
used to reject unreliable expansion plans. This
constraint may be nullified in which case the mini-
mum reserve percentage becomes the binding con-
straint.

The calculation of the reliability index is
based on a simplified and approximate method of
estimating the probability of loss of load (LOLP).
For the benchmark year, the cumulative probability
distribution of forced outages is computed by the
usual convolution process. The LOLP based on the
peak load for the benchmark year is calculated.
Its value is normalized to 1.0 and is the minimum
required reliability index.

The cumulative distribution of forced outages
is then approximated by four log-linear segments
evaluated at intervals equal to the standard devia-
tion of the distribution. The reliability index of
a future state is estimated by computing the mean
and standard deviation of forced outages, expressing
the reserve of that year in terms of standard devia-
tions above the mean value of forced outages, and
obtaining it from the log-linear approximations of
the distribution function for the benchmark year.

Maximum Number of Units:

Each generation alternative can be restricted
by a maximum number of units which are allowed to
be installed during the entire expansion period.

Method of Solution

The basic problem of generation expansion is
formulated as follows. Each year in the expansion
period is a stage. In each year, there are many
combinations of new units which form feasible states,
e.g., in the first year there may be three states,
one being one 900 MW nuclear unit, the second being
one 600 MW coal-fired unit, and the third being
three 100 MW gas turbines.

As the years progress, the number of states in-
creases because more new capacity is needed, and
there are many different combinations of the diffe-
rent types of units which can meet the requirement.
This is the so-called "curse of dimensionality"
because the computational requirement increases with
the number of states, which increases roughly
exponentially with the number of alternative types
of units.

Without some heuristic scheme of truncating the
number of states, it is impractical to solve a pro-
blem with more than three alternative types. The
heuristic truncation method which allows four or
even five alternatives to be run simultaneously will
be described later.

Forward Dynamic Programming:

The basic algorithm of forward dynamic program-
ming applied in the generation expansion problem
will now be described. Refer to Figures 1, 2 and 4.
This part of the algorithm is called forward because
it proceeds from the first year to the last, in
contrast to backward dynamic programming used later
and shown in Figure 3 which backtracks from the last
year.

Figure 4 shows an example with two types of
alternatives, a 400 MW fossil unit and a 54 MW gas
turbine, and a four-year expansion period, not
counting the benchmark year which is denoted by the
left-most circle with two zeros. In the first year,
the program finds two states which result in reserves
between the specified minimum and maximum and satisfy
the reliability index. They are (0,4) and (1,0),
indicating four gas turbines and one fossil unit,
respectively.

For each state, the program simulates the pro-
duction cost of the system and finds the state among
all states in the previous year which, when pro-
ceeding to the present state, does not necessitate
a deletion of a unit, and which results in a mini-
mum cost incurred up to the present year. For the
first year, the only feasible transition is from
(0,0) and the minimum cost is just the cost incurred
in the first year. This so-called cost-to-date is
the total operation and production costs and the
fixed charges, present-valued and cumulated up to
and including the present year. Thus the state
(0,4) requires a minimum of 76.3 million dollars to
reach it from the beginning.

The program then proceeds to the second year and
finds four feasible states, (0,10), (1,2), (1,4) and
(2,0). It simulates the production costs and for
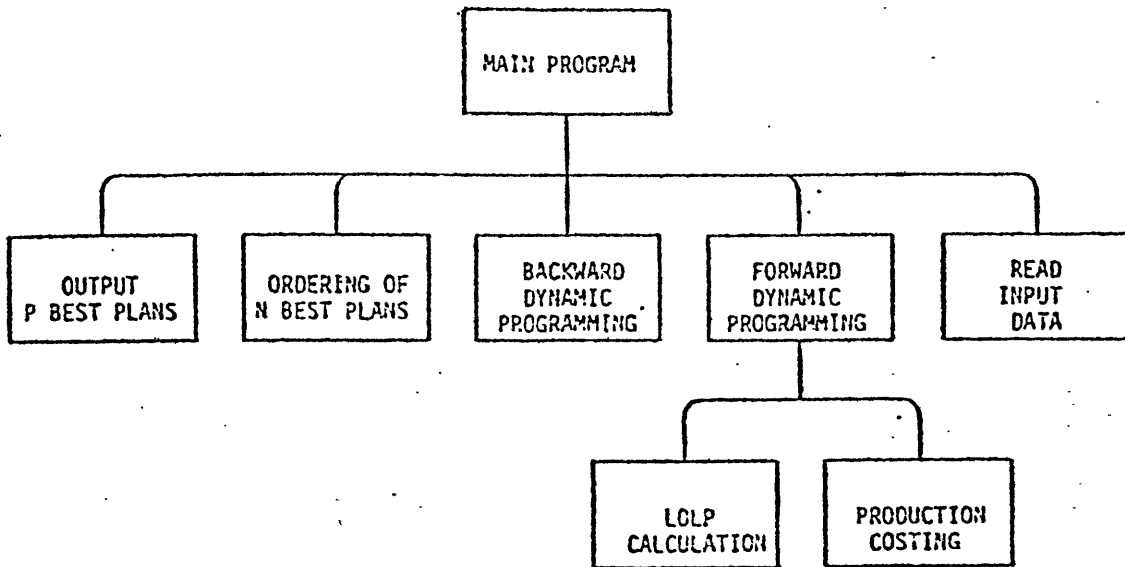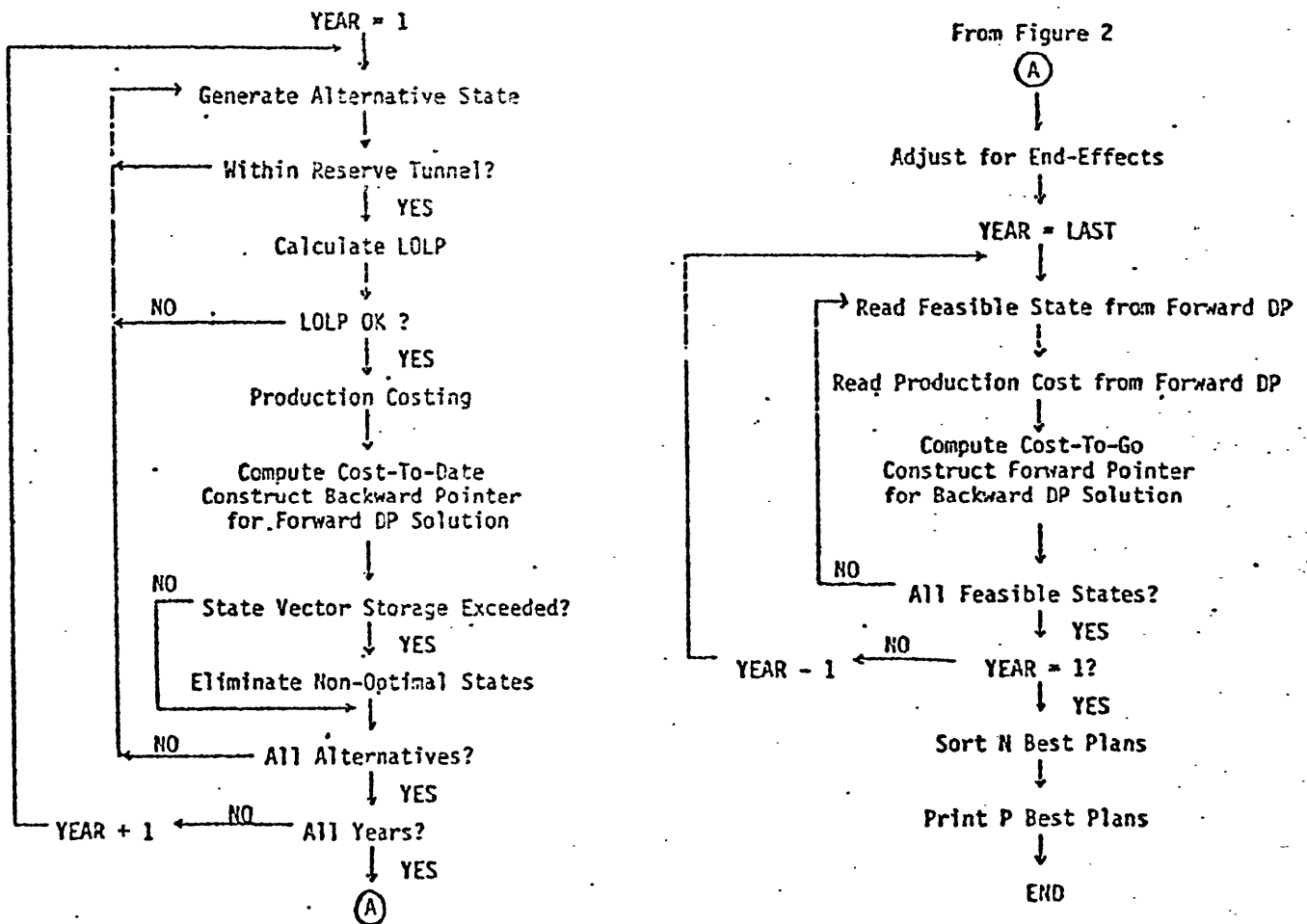each state, it looks back one year and from the two

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Figure 1. Functional Block Diagram of OPTGEN

Continued in Figure 3

Figure 2. Flow Chart of Forward Dynamic Programming

Figure 3. Flow Chart of Backward DP and Output

NOTATION FOR NEW UNITS INSTALLED

x = NO. OF 400 MW FOSSIL UNITS

y = NO. OF 54 MW GAS TURBINES
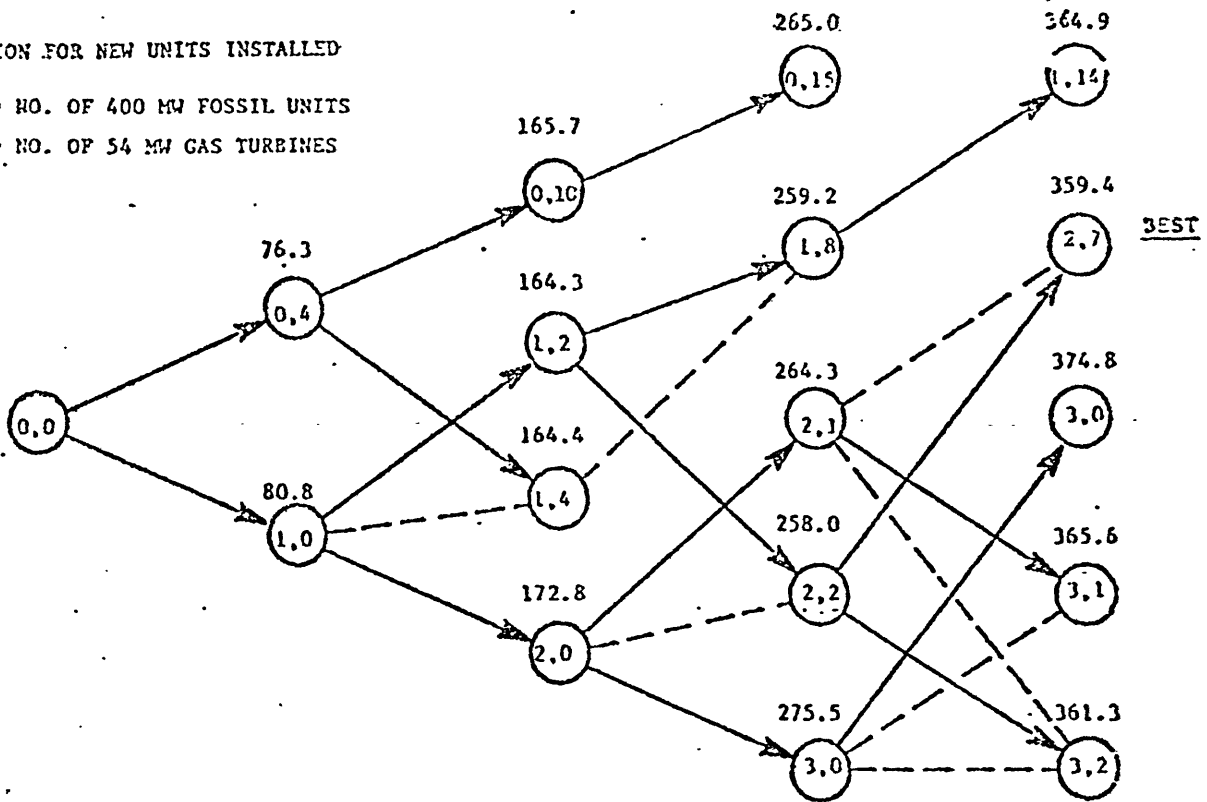
Figure 4. Generation Expansion by Dynamic Programming

previous states it determines which of them can proceed feasibly to the present state. For instance, (1,4) can come from both (0,4) and (1,0). Among these feasible prior states, the program computes the additional costs for the present and adds them respectively to the minimum costs of the prior feasible states. From these costs-to-date, it selects the minimum cost-to-date and remembers the transition from the prior state which yields the minimum. This is called the backward pointer. For example, (1,4) has a minimum cost-to-date of $164.4 million and the backward pointer is shown as an arrow coming from (0,4). The dotted line from (1,0) shows the other feasible transition.

The program proceeds in like fashion to the last year. At this point, the minimum cost-to-date for each state in the last year is calculated and then sorted to determine the minimum cost for all feasible transitions. In the example, (2,7) is the best state in the last year and the minimum cost is $359.4 million. To find the expansion schedule, it is only necessary to retrace the backward pointers. Thus the optimal plan is the following sequence of states: (0,0) - (1,0) - (1,2) - (2,2) - (2,7). Subtracting one state from the following state gives the unit added each year. The optimal installation schedule thus determined is listed below.

Year	Units Added 400 MW	54 MW
1	1	0
2	0	2
3	1	0
4	0	5

Derivation of 100 Best Plans:

If the objective is to find the optimal plan only, forward dynamic programming is sufficient. A plan can be traced backward from each of the terminal states with the backward pointers or solid arrows in Figure 4. This does not give too many suboptimal plans. Backward dynamic programming is used to increase the number of such plans.

In backward dynamic programming, the algorithm starts from the next-to-last year. For each state, it finds the feasible transitions to the following year and determines the transition which results in the minimum cost-to-go. The forward pointer indicates the cheapest forward transition from that state. The program then sweeps backward and repeats for all years until it reaches the beginning. In essence, it is the same as forward dynamic programming except for the reversal of direction. See Figure 3.

Since the screening process of determining whether a state satisfies the reserve and reliability criteria and the production costing have already been done in the forward algorithm, this part takes much less time. When both methods are combined as in this program, the number of suboptimal plans which are available is limited only by the storage requirement.

Many of these plans may be identical for most of the years and are simply minor variations in the last two or three years. In order to obtain the significant suboptimal plans in the output, a number equal to the number of years in the end of the period for which minor variations may be ignored, can be

specified. For each group of plans which are identical up to the specified end years, the program will print only the cheapest plan. In this way, the top 100 plans will include a lot more plans with significant variations.

Production Decisions

Two methods of production costing are available: probabilistic and deterministic. This probabilistic method is similar to that in WASP. For computation efficiency, the deterministic method is usually used.

Deterministic Production Costing:

The method uses a trapezoidal approximation of the annual plant duration curve as reported by K.L. Hicks in 1959. It was found that the actual loading of generating units based on historical data could be approximated by a trapezoid in Figure 5 whose vertical height equaled the system generation capacity, whose width equaled 8,760 hours (a year) times the maximum capacity factor of the base load units, and whose area equaled the energy demand (MWhr) for that year. The energy generated by the individual units could be approximated by horizontal strips of the trapezoid if the vertical axis was subdivided according to the rated capacities of the units arranged in order of their energy cost (heat rate x fuel cost), with the inexpensive base load units at the bottom and the peaking units on top. The resulting capacity factors fit the actual data better than the conventional method of stacking units on the load duration curve, because all units including peaking units are loaded to various degrees.
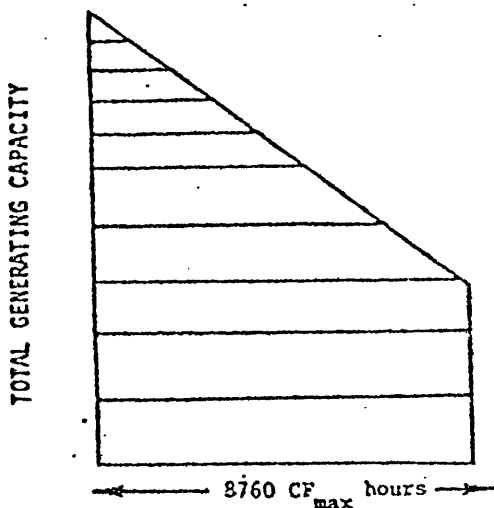
Figure 5. The Loading Trapezoid

It should be pointed out that this is a heuristic method which attempts to model the effect of random forced outages, maintenance outages and other operating peculiarities of the system on the loading of units.

The accuracy can be further improved by two calibration factors. A peaking constant which is used to increase or decrease the rated capacity of peak-

ing units in the formation of the trapezoid can be adjusted to change the loading of peaking units. Similarly, a cycling constant is specified to change the loading of cycling units.

The individual loading of all units can be fine-tuned by the use of individual maintenance factors, which derate the units in the loading triangle. The relation of the derated capacity of a unit used in the loading trapezoid to the maintenance factors is detailed in the following equation.

$$\text{Derated Capacity} = \text{Rated Capacity} \times (1 - \frac{\text{Maintenance Factor}}{\text{Base Value}})$$

In this fashion, the loading of a unit can be adjusted by varying the maintenance factor.

After the capacity factor of a unit is determined by the loading triangle, the energy cost is calculated by a reciprocal curve shown in Figure 6. H_{max} and H_0 are specified for each unit. H_{max} is the heat rate at maximum loading multipled by the fuel cost. H_0 can be adjusted to obtain the correct energy cost for lower capacity factor.
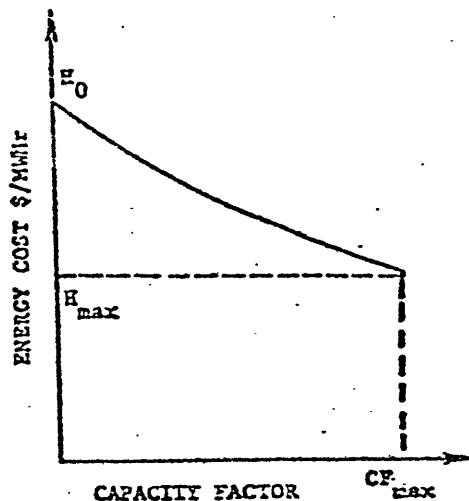
Figure 6. Energy Cost vs. Unit Capacity Factor

Investment Decisions

The investment decisions for generating units are made using dynamic programming as described previously. In order to limit the number of states considered, a truncation algorithm is used.

Truncation of Non-Optimal States:

The theory of state truncation is based on the assumption that the optimal plan is fairly close to being of minimum cost-to-date in each year up to the last year. This is especially true if the cost-to-date for each state is adjusted to account for the differences in the installed capacity, e.g., a state representing the addition of a big nuclear unit may have excess capacity for that year resulting in a

high cost-to-date, which when prorated by the minimum required capacity, may actually be less than the adjusted cost-to-date of a state with small units. The criterion for determining the minimum required capacity is either minimum percentage of reserve or fixed LOLP index.

The method of state truncation is to eliminate states in years when the number of states exceeds a specified number by first determining the minimum adjusted cost-to-date in the previous year. States in the previous year which have adjusted costs above a certain ratio to the minimum are then flagged. States in the present year whose backward pointers indicate a transition from a flagged state are then eliminated. If the resulting number of states in the present year still exceeds the maximum, the cost ratio is reduced by a factor more than once if necessary, and the elimination process repeated.

Selection of Plant Sites:

Generation expansion should ideally be solved together with transmission expansion. It is, however, not practical to do so. In most cases, transmission costs can be ignored in the generation expansion studies because they are small compared to the cost of generating capacity and they may be roughly the same for different generation expansion plans. In cases where plant sites are remote and transmission costs are significant, a model for including such costs is available in the program.

For each site, a cost-capacity step curve can be specified. A typical curve is shown in Figure 7. In this example, it is assumed that the first set of transmission additions related to this site costs $A and is sufficient for 400 MW of generating capacity. For the next increment of 400 MW capacity, the total transmission cost for this site jumps to $B, and so forth. The maximum capacity which can be built at this site is shown to be 1,600 MW.
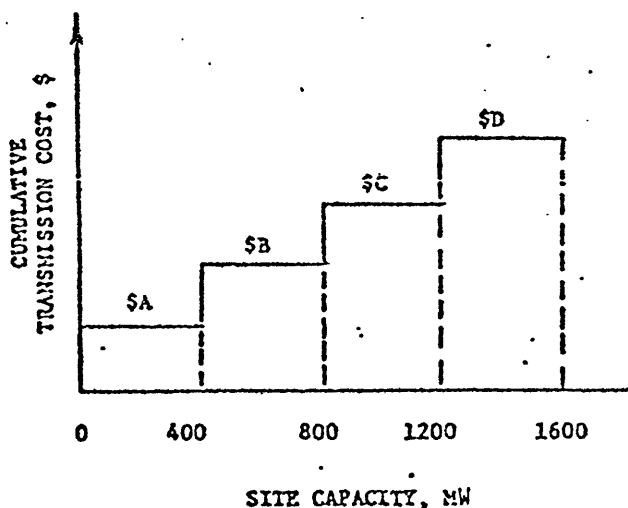
Figure 7. Transmission Cost-Capacity Step Curve

The program allows a first-available year to be specified for each site. During forward dynamic programming, the program assigns the new units to various sites such that the total transmission cost is minimized. The fixed charges for the transmission investment are added to the annual costs. The siting assignment, however, cannot be applied in backward dynamic programming. Therefore, only the best plans obtained by forward dynamic programming, which include transmission costs, are available.

Adjustment for End Effects:

Since different expansion plans may have different system capacities in the last year of the study period, it is not correct to compare their revenue requirements without some adjustment to account for the end effects. The reserve and reliability constraints are used to adjust the capacities in the last year to an equal basis, either minimum reserve percentage or fixed LOLP index. The fixed charges in the last year associated with the units newly installed in that year are prorated according to the adjustment in capacity. In other words, it is assumed that only portions of these units are installed in the last year.

Furthermore, the adjusted cost of the last year can be projected for any number of years and the present worth revenue requirements for this evaluation period is added to the objective function for minimization.

Limitations

Although the loading trapezoid method for production costing is extremely fast, its accuracy requires some calibration with a more detailed and accurate production costing model. No automatic procedure is available for that calibration and there is no assurance that the same set of calibrating factors is valid as the optimal expansion plan evolves.

Hydro and pumped storage units are not modeled in the production costing nor the investment alternatives.

Effect of maintenance on system LOLP is not taken into account in the approximate method of estimating LOLP. In fact, the annual distribution of daily peak loads is replaced by the single annual peak load.

The maximum number of states in any year is limited to 200. The study period cannot exceed 20 years and the maximum number of generation alternatives is 5.

Examples and Test Cases

Not available.

Performance Capability

Maximum core storage required for OPTGEN is 240 K bytes on an IBM computer.

APPENDIX C
U. MASS MODEL - A MATHEMATICAL PROGRAMMING MODEL FOR LONG-RANGE PLANNING OF ELECTRIC POWER GENERATION

F. Noonan
R.J. Giglio

University of Massachusetts

Scope

This is an optimization program that is used for planning investments in electric power generation. The program is used to help determine for each year over some planning horizon what types and sizes of generating plants should be brought into a power system in order to meet, reliably, the system's forecasted demands for electricity. The planning objective is to minimize the present worth of all investment and operating costs that are incurred for power generation over the horizon. The mathematical program that is formulated is large scale and has been both binary and nonlinear constraints. The solution algorithm employs Bender's Decomposition Principle, a heuristic successive linearization procedure, and a Branch & Bound mixed integer linear programming code. Computation costs are low and, in the important area of sensitivity analysis, the program offers additional economies which promise to make it attractive to power system planners. Computational results are presented for a full sized generation planning problem for the New England region of the United States.

Objective

The objective is to minimize

$$\sum_{t=1}^{T} \sum_{g=1}^{G} \sum_{m=1}^{M(t,g)} IC(t,g,m) \; Y(t,g,m)$$

$$+ \sum_{t=1}^{T} \sum_{i=1}^{I} \sum_{g=1}^{J} \sum_{k=1}^{K} F(i) \; DUR(k) \; OC(t,g) \; X_S(t,i,g,k)$$

where $IC(t,g,m)$ = The investment cost of one unit of the mth type project from class g in year t (see method of solution)

$OC(t,g)$ = The operating cost coefficient ($/MWH) for the gth class in year t

$F(i)$ = The frequency of the number of weeks/yr. the ith operating week occurs

$DUR(k)$ = The number of hours/week the kth demand occurs

T = Number of years on planning horizon

I = Number of production subproblems used per year to model seasonal variations in demand and available capacity

K = Number of different demand levels used in modeling weekly demand

G = Total number of generating classes

J = Number of thermal generating classes

$M(t,g)$ = Number of alternative investment projects available from the gth class in year t

$Y(t,g,m)$ = Number of projects of mth type to be installed from class g in year t

$X_S(t,i,g,k)$ = Prod. level in MW of the gth class for k^{th} demand in i^{th} operating week for year t

Constraints

If the gth class is to be treated as continuous since only one relatively small plant site is available, $M(t,g) = 1$ and $Y(t,g,1)$ is continuous. Otherwise $Y(t,g,m)$ is discrete (0,1) and satisfies

$$\sum_{m=1}^{M(t,g)} Y(t,g,m) \leq 1 \; \forall t$$

The system reliability constraint is in terms of the probability that the total available capacity (after preventive maintenance) is less than the annual peak demand. This is expressed analytically by the following approximations:

$$\left[PMF \cdot \overline{C}_t - \overline{d}_t \right] + G(R^*) \sqrt{PMF^2 \cdot \overline{C}_t + \tilde{d}_t} \geq 0$$

$$G(R^*) = a_1 - a_2 \sqrt{\ln\left(\frac{1}{R^*}\right)^2}$$

where d_t = Annual peak demand (normal random variable with mean $\overline{d}_t$ and variance $\tilde{d}_t$)

R^* = Max. allow. value for peak risk

PMF = One minus the fraction of installed capacity down for preventive maintenance at the time of the annual peak.

a_1, a_2 = Coefficients determined by "fitting" the analytic constraint to the actual stochastic constraint

C_t = Available capacity for peak demand without maintenance scheduling

$\bar{C}_t$ = Mean of above

$\breve{C}_t$ = Variance of above

If EC(t,τ,g,m) and VC(t,τ,g,m) denotes the mean and variance, respectively, of the available capacity for the (τ,g,m) project in year t, and IEC and IVC refers to existing groups at t=0,

$$\bar{C}_t = \sum_{\tau=1}^{t} \sum_{g=1}^{G} \sum_{m=1}^{M(\tau,g)} EC(t,\tau,g,m) \, Y(\tau,g,m)$$

$$+ \sum_{g=1}^{G} IEC(t,g)$$

$$\breve{C}_t = \sum_{\tau=1}^{t} \sum_{g=1}^{G} \sum_{m=1}^{M(\tau,g)} VC(t,\tau,g,m) \, Y(\tau,g,m)$$

$$+ \sum_{g=1}^{G} IVC(t,g).$$

The optional plant mix constraint to restrict investment in certain classes is

$$\sum_{\tau=1}^{t} \sum_{m=1}^{M(\tau,g)} NC(\tau,g,m) \, Y(\tau,g,m) + INC(t,g)$$

$$\left\{ {\leq \atop \geq} \right\} PMIX(g) \cdot TNC_t$$

NC, INC = Name plate capacities

PMIX(g) = Fraction of total installed capacity (TNC_t)

$$TNC_t = \sum_{\tau=1}^{t} \sum_{g=1}^{G} \sum_{m=1}^{M(\tau,g)} NC(\tau,g,m) + \sum_{g=1}^{G} INC(t,g)$$

The demand constraint for production in each of the T·I weekly subproblems is

$$\sum_{g=1}^{G} X_S(t,i,g,k) - \sum_{p=1}^{P} X_c(t,i,p,k) \geq DEM(t,i,k)$$

where DEM = Level in MW of the demand

$X_c(t,i,p,k)$ = Demand placed on the system by the pumped hydro class p (there are P classes).

Power capacity constraints for each subproblem are

$$X_S(t,i,g,k) \leq TEC(t,i,g)$$

$$X_c(t,i,p,k) \geq TEC(t,i,J+H+P)$$

H = Number of conventional hydroelectric generation classes

TEC(t,i,g) = Total expected available capacity

= PMD(i,g) SVM(i,g) FOM(i,g)

$$\left[\sum_{\tau=1}^{t} \sum_{m=1}^{M(\tau,g)} EC(t,\tau,g,m) \, Y(t,\tau,g,m) + IEC(t,g) \right]$$

PMD = Preventive maintenance derating factor

SVM = Seasonal variation multiplier

FOM = Forced outage derating multiplier

The usage level constraints for each weekly subproblem are

$$\sum_{k=1}^{K} DUR(k) \, X_S(t,i,g,k) \left\{ {\leq \atop \geq} \right\} V(g) \cdot TEC(t,i,g)$$

and V(g) = Usage level multiplier which converts available power capacity to either a min. or max. weekly energy level for that class.

Each weekly subproblem has, in addition, pumped hydroelectric constraints to insure water levels each week are returned to their former levels.

$$\sum_{k=1}^{K} \left[X_S(t,i,J+H+P,k) - E(p) \cdot X_c(t,i,p,k) \right]$$

$$\cdot DUR(k) \leq 0$$

E(p) = Pumping efficiency

Method of Solution

Thermal plants are classified in distinct groups in terms of operating costs. Hydroelectric plants which have no operating costs are classified in terms of the ratio of weekly energy capacity to power capacity. Since system planners are usually limited in the number of alternatvie investment projects, the set of available plant sizes is finite. Only one-

project can be chosen from each generation class in each year.

The structure of the problem may be represented as follows where y represents the investment decision vector and x_{ti} the operating decision vector:

$$\min. \ \underline{c}^T \underline{y} + \underline{h}_{ti}^T \underline{x}_{ti}$$

Subject to

$$\underline{y} \in S_1$$

$$\underline{y} \in S_2$$

$$D\underline{y} \leq d$$

$$\underline{y} \geq 0$$

$$A\underline{x}_{ti} + B_{ti} \ \underline{y} \geq \underline{b}_{ti}$$

$$\underline{x}_{ti} \geq 0$$

where S_1 = {Y|Y obeys the nonlinear reliability constraint}

S_2 = {Y|Y(t,g,m) = 0 or 1 if g is a discrete class}

Let S = $S_1 \cup S_2 \cup \{y|Dy \leq d, y \geq 0\}$

Then given a particular $\underline{y}$, it is seen that the weekly subproblem becomes

$$\min \ \underline{h}_{ti}^T \underline{x}_{ti}$$

Subject to

$$A\underline{x}_{ti} \geq (\underline{b}_{ti} - B_{ti} \ \underline{y})$$

$$\underline{x}_{ti} \geq 0$$

After an appeal to Bender's decomposition principle, the entire program is defined as

$$\min_{Y \in S} \left\{ \underline{c}^T \underline{y} + \max_{w^n \in W} \left\{ \sum_{t=1}^{T} \sum_{i=1}^{I} (\underline{b}_{ti} - B_{ti} \ \underline{y})^T \right\} \underline{u}_{ti}^n \right\}$$

where $\underline{w}^n$ = $\left\{ \underline{u}_{11}^n \ \ldots \ , \underline{u}_{ti}^n, \ \ldots \ , \underline{u}_{TI}^n \right\}$

and w^n = The nth dual basic feasible solution to the production subproblem.

$$W = \left\{ \underline{w}^n, n=1,2,\ldots;N \right\} = \left\{ A^T \underline{u}_{ti} \ h_{ti}; \underline{u}_{ti} \ 0, \forall t, i \right\}$$

Although the set W is not available, it is possible to apply the decomposition principle indirectly

through an iterative algorithm.

Define $W_{n+1} = W_n \cup \left\{ w^{n+1} \right\}$ $W_1 = \left\{ w^1 \right\}$ $n = 1, 2, \ldots,$

Then given W_n, the decomposed master problem is solved for y using $W = W_n$. This defines a feasible (although generally non-optimal) investment plan Y and an upper bound for the cost. Next, under the investment outlined the $T \cdot I$ weekly subproblems are solved and the total cost derived. In addition, another dual feasible solution is added to the set W_n to obtain W_{n+1} for the next iteration. As this algorithm proceeds, $W_n \rightarrow W$ and the cost upper bound converges to the minimal cost of the original program.

Due to the nonlinear constraints on y, a heuristic procedure based on successive linearizations is employed. Each time the set of dual basic feasible solutions is augmented, the reliability constraints are re-linearized.

Suppose at the $n-1^{th}$ iteration of the master program the reliability constraints (S_1) had been linearized and represented as

$$g_t(\underline{y}) \geq 0 \quad t=1, \ldots, T$$

Then the new constraints for the nth iteration are

$$g_t(\underline{s}^n) + (\underline{y} - \underline{s}^n)^T \nabla g_t(\underline{s}^n) \geq 0$$

where

$$\underline{s}^n = (1 - \alpha) \ \underline{s}^{n-1} + \alpha \underline{y}^{n-1} \quad \alpha \in (0,1)$$

and y^{n-1} is the solution obtained on the n-1 iteration. A mixed integer code is used to implement the programming procedure with the linearized constraints. The initial $\underline{y}$ is arrived by ansatz and the set W is initialized with a number of corresponding dual basic feasible solutions.

Production Decisions

For a complete discussion of the role production plays in the programming method, see above. In addition, we should note that associated with each operating subproblem there is a "frequency parameter" indicating the number of weeks during the year that a particular weekly allocation subproblem is assumed to occur. The total cost is the sum of every cost corresponding to the subproblem weighted by these "frequency parameters". Each weekly allocation subproblem is characterized by a weekly demand model power capacity available from each generating class and weekly energy capacity for each hydroelectric class. The duration parameter associated with the demand level defines the number of hours/week that demand is at the level specified by the corresponding demand level. Available power capacity in each generation class is given by a linear derating to represent preventive maintenance and forced outage.

Investment Decisions

The optimal investment program is arrived at through an iterative algorithm described in Method of Solution. All costs are defined in present worth and investment costs are represented as a single cash outlay occurring at the time of installation. Included are property taxes, insurance, depreciation, fixed O&M costs and other costs independent of operation. End effects are treated by assuming that demand is constant after the planning horizon and plants slated for retirement are replaced by identical plants. Due to increases in reliability as plants mature, excess capacity may result from installation of too many plants at the end of the planning horizon. This problem is alleviated by an artificial extension of the planning horizon by an amount equal to the maximum immature period of all generation alternatives.

Limitations

Plant capacity is not allocated on a plant by plant basis, rather on the aggregate level of each generation class. Linearization approximations are used to derive operating cost coefficients for fuel and variable O&M. The iterative algorithm is terminated when cost convergence as well as convergence in feasibility occurs. If the cost obtained from the solution of the linearized master program is within a specified error of the total cost of the investment plan, convergence in cost is said to occur. Feasibility convergence requires that the linearized and actual reliability constraint functions are sufficiently close at that iteration. Plant location decisions and necessary investments in transmission and distribution equipment are not considered.

Examples and Test Cases

With the hope of duplicity, a 1971 problem which had been previously solved was solved using this approach. A planning horizon of 1977-1995 was specified. The cost of capital was fixed at 8.6%, and the maximum allowable peak risk was 0.000385 (no more than one day of failure per 10 years elapsed).

    # Discrete Gen. Classes   = 2
    # Conts. Gen. Classes   = 2
    # Gen. Classes not under invstmt.
      alternatives   = 10
    # Thermal Gen. Classes   = 0
    # Conventional hydroelectric classes = 3
    # Pumped hydroelectric classes   = 3

    New Investment alternatives:
      Nuclear-Discrete
      Intermediate Fossil-Discrete
      Gas Turbines (245MW)- Continuous
      Pumped Hydroelectric (250MW) - Continuous

Twenty alternative investment projects are permissible in the discrete classes.

To reduce the excessive computation time, the linearized master program was decomposed into three 9-year master subproblems with respective starting date of 1, 6, and 11 years. This results in a restriction of the solution space and a consequent increase in minimum cost. Due to uncertainties in many variables, these introduced errors may not be significant, however.

Most of the expansion program was made up of nuclear projects. Total cost was $18499.7\cdot10^6$ composed of $13201\cdot10^6$ investment costs and $5298\cdot10^6$ operating costs.

Performance Capability

The above test case converged with nine iterations of the solution method. One hour of CPU time on a CDC 3600 was required which was composed of 53% spent solving production allocation subprograms and 47% in solving the master programs. It has been implemented in batch mode on a CDC 6600 computer; total computation time was 426 system seconds and the core requirement was 300 K octal words.

APPENDIX D
MIT MODEL - ECONOMIC ENVIRONMENTAL SYSTEM PLANNING PACKAGE

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Scope

The Economic-Environmental System Planning Package is a set of generation expansion planning programs designed to explicitly consider the feasibility and cost of meeting environmental standards. Various parts of the package have evolved from the ALPS expansion planning model, developed at the Hanford Engineering Development Laboratory, as well as several power system operation and environmental models developed at MIT.

As a generation expansion planning tool, the model exhibits several unique characteristics:

- Expansion alternatives are characterized by a plant type, fuel type, nominal capacity, site type, thermal pollution abatement technology and air pollution abatement technology.

- The cost and performance characteristics of air pollution controls are explicitly incorporated.

- The feasibility of expansion alternatives is tested by comparing performance to emission and ground level air quality standards.

- The required minimum stack height for meeting air quality standards is determined.

- The cost and performance of water pollution controls are explicitly incorporated.

- The feasibility of expansion alternatives is tested by comparing performance to water quality standards.

- The required design characteristics of water quality control technologies are determined.

- Consumptive water use, land requirements and environmental residuals are also determined.

- The incorporation of a site availability constraint.

The following characteristics apply to the more conventional aspects of the package:

- Plant types can include hydro and pumped storage.

- Incorporates both capacity and energy constraints in determining the need for new units.

- Incorporates constraints on the rate of introduction of new unit types.

- Incorporates fuel availability constraints, including detailed representation of nuclear fuel requirements.

- Utilizes separate production cost model.

Objective

The objective function is the sum of the present worth of future capital and operating costs, given as follows:

$$Z(T) = Z_{plant}(T) + Z_{fuel}(T)$$

$$Z_{plant}(T) = \sum_{v=1}^{T} \sum_{j=1}^{J} C_{jv} \cdot X_{jv}$$

$$Z_{fuel}(T) = \sum_{t=1}^{T} \sum_{v=-V}^{t} \sum_{j=1}^{J} F_{jvt} \cdot CAPFAC_{jvt}$$
$$\cdot PER_t \cdot CAP_{jv} \cdot X_{jv}$$

where $Z(T)$ = Total capital and operation costs (dollars) associated with a given system design over time interval $0 \le t \le T$

v = Time at which alternative becomes operational $-V \le v \le T$

J = Total number of alternatives

C_{jv} = Present worth of capital and operating (other than fuel) costs of an alternative of type j and vintage v (dollars)

X_{jv} = Number of type j alternatives with vintage v to be built

$CAPFAC_{jvt}$ = Capacity factor in period t of type j alternative with vintage v $0 \le CAPFAC_{jvt} \le 1$

PER_t = Length of period t (hours)

CAP_{jv} = Capacity of an alternative of type j and vintage v (kW)

The expansion model selects the decision variables X_{jv} and $CAPFAC_{jvt}$ (see section on solution techniques for the method of determining $CAPFAC_{jvt}$) which minimize $Z(T)$, subject to the constraints imposed.

Constraints

Several constraints are utilized in the formulation of the expansion planning model which aids in the reduction of feasible sets of plant expansion alternatives.

One of these is an installed capacity constraint which effectively operates as a reserve margin criteria. It is formulated as follows:

$$\sum_{j=1}^{J} \sum_{v=-V}^{t} PAV_{jvt} \cdot CAP_{jv} \cdot X_{jv} \ge MAXLOAD_t \cdot (1 - \xi_t)$$

$$t = 1 \ldots T$$

where PAV_{jvt} = Mean expected availability in period t of plant type j with vintage v

CAP_{jv} = Capacity of plant type j with vintage v

X_{jv} = Number of type j alternatives with vintage v to be built

$MAXLOAD_t$ = Mean expected maximum system load in period t

ξ_t = Required margin of spare capacity in period t

The model also utilizes an energy demand constraint to ensure sufficient total energy is available from the installed additions. The constraint requires that the energy produced in period t by all plants built before period t (except pumped storage plants) minus the transmission and pumping losses associated with the pumped storage plants, must be greater than or equal to the expected energy demand in period t.

Algebraically,

$$\sum_{j \in PS} \sum_{v=-V}^{t} PER_t \cdot CAPFAC_{jvt} \cdot CAP_{jv} \cdot X_{jv}$$

$$\sum_{j \in PS} \sum_{v=-V}^{t} (1/\eta_{jv} -1) \cdot PER_t \cdot CAPFAC_{jvt}$$

$$\cdot CAP_{jv} \cdot X_{jv} \geq ED_t$$

$$t = 1 \ldots T$$

where PER_t = Length of period t

η_{jv} = Overall efficiency of a pumped storage hydro plant of type j and vintage v

ED_t = Mean expected energy demand in period t

Note that this formulation does not allow energy to be stored from one time period to the next.

The program also incorporates constraints which permit existing and previously committed units to be included in the set of future generation units. Their respective formulations are as follows:

$$X_{jv} = XC_{jv} \quad \text{for existing units}$$

$$X_{jv} \geq XC_{jv} \quad \text{for committed units}$$

where XC_{jv} = Number of plants of type j with vintage v previously built or committed

The program includes a constraint which limits the rate at which new units of a given plant type can be added to the system. The following formulation is used:

$$\sum_{j \in R_i} X_{jv} \leq XR_{iv}$$

where R_i = Set of plant types included in class i

XR_{iv} = Cumulative number of plants in plant type class i that may be built in vintage period v

Two different plant siting constraints are utilized in the model; one is for hydro and pumped storage plants and one is for thermal plants.

The hydro site constraint limits the number of hydro or pumped storage plants of capacity HSZ_h or larger to be equal to or less than the specified number of sites which can support plants of capacity HSZ_h or larger.

Algebraically,

$$\sum_{j \in HS_h} \sum_{v=1}^{T} X_{jv} \leq NHSA_h$$

where HS_h = Set of all hydro and pumped hydro plants with capacity HSZ_h or greater

$NHSA_h$ = Number of hydro sites available which can support hydro or pumped hydro plants of capacity HSZ_h or greater

The thermal site constraint is similar, except that it measures site size in terms of four environmental resources, air pollution, land use, water use and heat dissipation, as follows:

$$\sum_{j \in TS_{alcws}} \sum_{v=1}^{T} X_{jv} \leq NTSA_{alcws}$$

where TS_{alcws} = The set of all thermal plants which require site type s with at least the quantity of environmental resources as indexed by a, l, c, and w.

a = Index of air pollution level

l = Index of land amount

c = Index of consumptive water use

w = Index of heat dissipation capacity

$NTSA_{alcws}$ = Number of sites of type s available which can support thermal plants with the environmental resource requirements indexed by a, l, c, and w or greater.

In addition to several constraints relating to nuclear fuels (not discussed here because of the detail involved), the program also recognizes two types of fossil fuel constraints. One concerns limiting the amount of fuel available at a given price level, as follows:

$$\sum_{t=1}^{T} NFP_{fmt} \leq UFA_{fm}$$

$$f = 1 \ldots 13$$

$$m = 1 \ldots M_f$$

where NFP_{fmt} = Amount of fuel type f purchased in period t at price level m

UFA_{fm} = Quantity of fuel type f available at price level m

The second fuel constraint works in conjunction with the first, and limits the amount of fuel consumed to the amount purchased in a given period, or

$$\sum_{j \in F} \sum_{v=-V}^{t} FC_{fjvt} \cdot X_{jv} = \sum_{m=M_f} NFP_{fmt}$$

$$t = 1 \ldots T$$

$$f = 2 \ldots 13$$

where F = The set of fossil fuel types

FC_{fjvt} = The amount of fuel of type f (f = 2 . . . 13 for fossil fuels) consumed by a plant of type j and vintage v in period t

NFP_{fmt} = The amount of fuel type f purchased in period t at price level m

The preceding constraints are an integral part of the plant expansion component of the economic-environmental system planning package. Two related sub-models which evaluate the air and water environmental performance of expansion alternatives also contain logic which constrains the choice of future plant additions.

The air quality model constrains the choice of alternatives to those which do not meet the following user-definable criteria:

● Stack emission standard

● Three-hour ground level air quality standard

● Twenty-four hour ground level air quality standard

● Annual ground level air quality standard

The logic incorporated in this sub-model includes a dispersion model to calculate the revelant performance measures for various types of sites.

The water quality model performs similar types of constraint actions for alternatives which cannot meet user-specified water quality criteria, viz:

● The plant requires more than a specified limit of river or estuary flows

● The dilution flow, if required, is greater than twice the normal plant cooling water flow

● The temperature standards cannot be met within defined mixing zone with maximum dilution flow

● A small lake site has a loading less than or equal to 0.5 acre per megawatt

● The Froude number for a surface discharge is less than 3.6 or greater than 25

Method of Solution

As presently configured, the Economic-Environmental System Planning Package is comprised of four major parts, each possessing a number of sub-models. They are the Generation Expansion Model (GEM), the Site Evaluation: Air Model, the Site Evaluation: Water Model and the Production Cost Model.

The expansion planning algorithms themselves are contained within the GEM portion of the model. Using estimated capacity factors for generating units, the sub-models of GEM perform the accounting and some constraint violation tests and prepare the plant data for the expansion optimization. The optimization procedure itself is an IBM-supplied linear programming code designated MPSX (Mathematical Programming System Extended), which uses the revised simplex method of solution with bounded variables and range constraints.

Following the optimization, plant additions are transferred to the probabilistic simulator SYSGEN to determine optimum capacity factors for these unit additions. (The use of SYSGEN is not to be confused with the "Production Cost Model", which has an environmentally-oriented purpose.) The resulting capacity factors from SYSGEN form the basis for a new capacity factor estimate to be used in the optimization routine. The optimization routine and SYSGEN thus form an iterative loop which is repeated until the capacity factor estimates converge.

The Site Evaluation: Air Model works in conjunction with the accounting portions of GEM. It consists of a boiler model, which contains emission factors for different fuels and boiler firing patterns; a minimum stack height model; and a meteorological dispersion model using the double Gaussian dispersion formula. The dispersion and stack height models are used iteratively until either the air quality standards are met or the maximum stack height is reached. Infeasible solutions are passed back to the GEM accounting routines. Cost and operating data are also transferred.

The Site Evaluation: Water Model also works in conjunction with the accounting portions of GEM. Various engineering models are used to determine the performance of plants in different types of cooling and discharge situations. Infeasible solutions, costs and performance data are transferred back to GEM.

The Production Cost Model is separate and not to be confused with SYSGEN, the probabilistic simulation routine. The Production Cost Model is a time sequence simulator for more closely analyzing environmental performance over a limited time period, such as minimum stream flow conditions during a specific season.

The Production Cost Model consists of a maintenance scheduler and a unit commitment simulation. The actual formulation of these sub-models is unclear from the standpoint of their respective objective functions. The maintenance scheduler, which is stated to be formulated as a mixed-integer program, is claimed to have the capability

of maintenance scheduling and unit shut-down for either economic or environmental reasons. The Unit Commitment Model, which is formulated as a linear program, is said to produce operating costs as well as air and water environmental impacts.

The exact purpose of the Maintenance Scheduler and Unit Commitment Model are somewhat unclear since, on the one hand, a long-range planning solution would not involve the associated amount of detail and, on the other hand, if done more precisely, would involve a much more refined technique than is apparently intended in the models described.

Production Decisions

As stated earlier, the Production Cost Model utilized by GEM is the probabilistic production simulator SYSGEN. While the iterative procedure between SYSGEN and the linear programming optimization is somewhat unique, the actual production cost code is based on the Booth-Balerieux approach. Since this approach is well-known, no further discussion of the particular formulation appears warranted.

What is unclear, however, is the actual performance of the iterative procedure and its ability to converge with the year-by-year and plant-by-plant results of SYSGEN. Available documentation does not permit an evaluation of this aspect of the model's performance.

Investment Decisions

The linear programming formulation of the optimization procedure will determine a near-optimum set of system investments over time from the alternatives supplied. Since all time periods are considered simultaneously, the dynamics of the problem are properly considered. Some error may be introduced by linearizing the discrete nature of actual unit additions. As previously discussed, the actual model performance is dependent upon the ability to converge the estimates of unit capacity factors.

Limitations

Based upon available information, no inherent program limitations have been identified.

Examples and Test Cases

Not available.

Performance Capability

Not available.

APPENDIX E
PUPS - PLANNING OF UNCONVENTIONAL POWER SOURCES

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Scope

PUPS was designed for the purpose of studying the economic feasibility of tidal power in the Bay of Fundy. It develops a near-optimal long-range generation expansion plan for a region, using screening curves and snapshot-year analysis. The resulting plan is, therefore, made up of a series of static optimizations.

The following combination of features makes it a unique tool:

- Chronological simulation of hydro, pumped storage, and system absorption of unconventional power sources

- Mix of thermal generation is optimized by screening curves for the snapshot years

- LOLP criterion is met by adding combustion turbines

- Expansion plan between snapshot years is interpolated

- Automatic comparison of an alternative expansion plan against the base case plan to provide the cost differences

- Up to 500 generating units can be modeled and 50 years of expansion is still computationally feasible

Objective

No explicit objective function is used in the PUPS program because it is only a pseudo optimization program. It is, however, equivalent to a series of static optimizations of the generation mix for each snapshot year with interpolation in between. The static optimization is accomplished using screening curves which traditionally have been used by system planners.

The implicit objective of the screening curves is to minimize the annual cost of the power system for the snapshot year. The annual cost consists of the following components:

(1) Annual fixed charge of new generating units to be added, including fixed O&M

(2) Annual fuel cost and variable O&M for new generating units serving the entire system load

The procedure is only a true optimization if there is no existing generation, the system load remains constant and unit sizes are not discrete. However, for long-range studies, the procedure produces results that closely resemble optimal expansion plans derived by more sophisticated dynamic optimization models.

Constraints

For the planning functions of the model, the following constraints are imposed:

Reliability Constraint:

The generation system for each snapshot year must satisfy an LOLP criterion. Two definitions of LOLP are possible:

(a) LOLP is based on 250 daily peak loads, or

(b) LOLP is based on hourly loads over the entire year.

In either case the effect of maintenance can be approximated as an option.

In between snapshot years, the reliability constraint takes the form of a minimum reserve percentage, linearly interpolated between the reserve requirements of the two snapshot years.

Capacity Factor Constraints:

The addition of nuclear units is limited by a specified minimum annual factor below which nuclear units cannot be technically operated. This overrides the economic penetration of nuclear units.

A maximum capacity factor can be specified for combustion turbines to limit their economic expansion.

Method of Solution

The program uses a snapshot-year approach. The intervals between snapshots can be varied from snapshot to snapshot. For each snapshot year, a detailed hour-by-hour simulation of the operation of the non-thermal generation system is made. This is performed by CATO. See Figure 1 for the functional block diagram of the sub-models used in a snapshot year.

The hydro system and storage expansion are input data. The result of CATO is the annual thermal load duration curve which is used for both OPTMIX-TCC and PROCOX. OPTMIX applies the screening curves to the thermal LDC and derives the expansion of the non-peaking thermal generating units from the previous snapshot to the current snapshot year. The peaking combustion turbines are added one at a time by TCC until the LOLP criterion is met. The resulting thermal system structure is combined with the thermal LDC in PROCOX to compute the annual thermal production cost.

After a snapshot analysis is completed, the year-by-year expansion plan between the previous and the current snapshot years is obtained by FILLIN which basically arranges the schedule to match the optimal mix as closely as possible and at the same time satisfy the minimum reserve constraint.

The annual revenue requirements are computed and their present worths cumulated as the snapshot analysis marches forward in time. At the completion of the last snapshot year, the annual cost of the last year is projected to any number of years to form the evaluation period.

Production Decisions

The simulation of the production decisions in the operation of the generation system is performed by CATO and PROCOX. Their basic functions and algorithms are summarized below.

Scheduling of Non-Thermal Generation by CATO:

The objective of the CATO model is to determine in each snapshot year, the generation schedule of
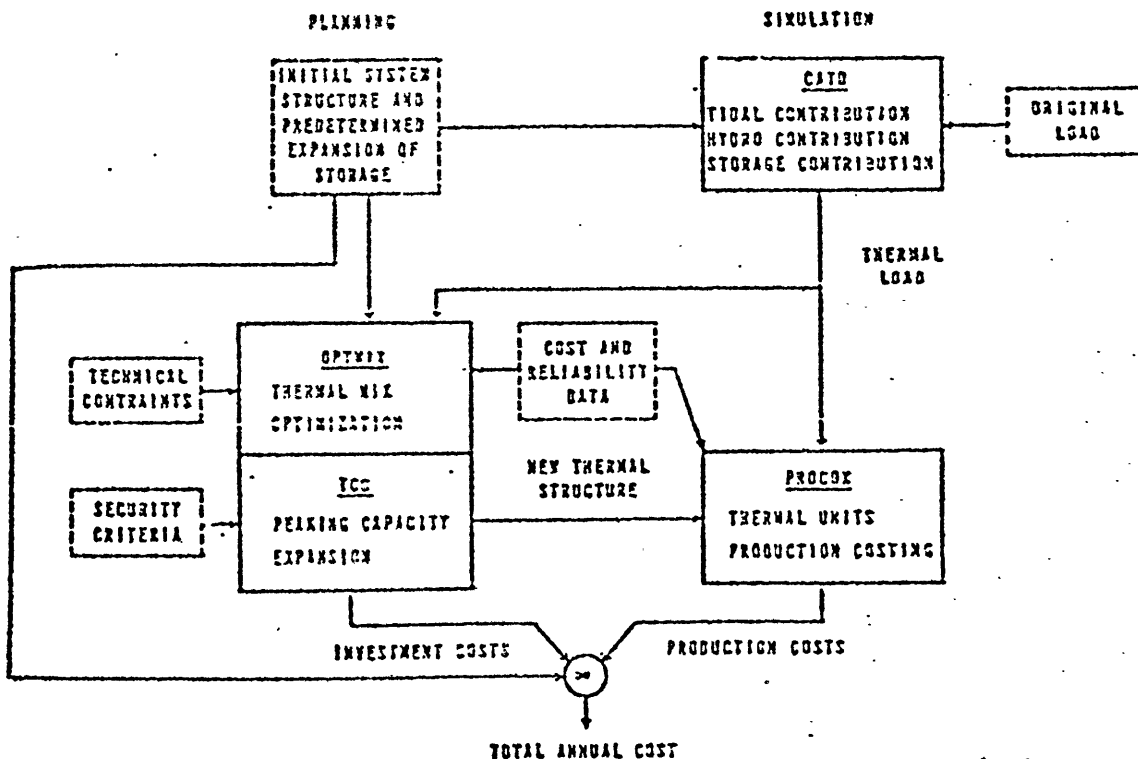
Figure 1. Functional Relationships for Snapshot Year Analysis

all the non-thermal resources, in order to identify the residual load which is to be supplied by the thermal system.

The method of approach is a deterministic simulation based on a chronological load model of 8736 hourly loads. No optimization is performed. Rather, decision rules are applied to approximate an optimal scheduling policy. The scheduling sequence is as follows:

(1) Must-run generation

(2) Unconventional generation

(3) Controllable hydro

(4) Storage devices

The absorption from unconventional generation, the generation from all hydro units and the restitution from storage are deducted from the original load. The storage pumping schedules from thermal generators are added to the original load. The resulting load is to be supplied by the thermal units. That load is referred to as the thermal load.

A second result of CATO is the time series of residual unconventional generation unabsorbed in the primary market and available to the secondary market.

Algorithms for Utilizing Unconventional Generation: CATO applies the following decision rules for simulating the utilization of unconventional generation.

(a) Direct Absorption: The basic limitation in determining the direct absorption is the must-run generation. Three components are identified in the must-run generation: hydro, nuclear, and fossil must run. The load above the must-run generation can be supplied by direct absorption from tidal generation.

(b) Retiming Policies: Three different storage policies can be simulated in CATO, depending on the characteristics of the storage devices made available for retiming the residual.

• Policy A
A storage device is dedicated to retiming of unconventional generation and is operated on a weekly basis.

• Policy B
A storage device is dedicated to retiming of unconventional generation and is operated on the same cycle as the unconventional generation.

• Policy C
All storage devices in the system are used for peak shaving. Priority is for retiming unconventional generation. The retiming is simulated on a weekly basis.

Algorithms for Scheduling Hydro and Storage Devices: Hydro generation is scheduled by peak shaving with a predetermined amount of hydro energy on a weekly basis. The basic algorithm for scheduling storage devices is similar. The generation schedule is determined by peak shaving but the amount of energy is unknown. The charging schedule is found by valley filling the same amount of energy divided by the round-trip efficiency. The amount of cycled energy is determined iteratively to reach the optimal economic conditions subject to the energy storage capacity constraint.

The optimal economic condition is approximated by the following inequality:

$$(p - NUCAP) \leq \gamma \ (r - NUCAP)$$

where p and r are the pumping and restitution load level, respectively. NUCAP is the total derated nuclear capacity in the system and γ is the roundtrip efficiency.

The above assumes that pumping with nuclear energy is always economical and that the system incremental cost function is proportional to load level above the nuclear capacity.

Annual Thermal Production Costing by PROCOX:

The PROCOX model estimates the annual production cost associated with a given thermal load and a set of thermal generating units.

The method of approach is based on an annual thermal load duration curve with derated unit capacities for incorporating the effect of forced and planned outages.

The units are stacked under the thermal LDC according to average operating cost. Each unit is derated: base load and cycling units by forced outage and maintenance, and peaking units by forced outage only.

The main result of PROCOX is the annual production cost for the entire system. Other results are:

• System fuel consumption and cost per fuel type.

• Capacity factor, or equivalently the energy production of each unit

• Fuel cost and O&M cost for each unit

Investment Decisions

The investment decisions are made for a snapshot year by the OPTMIX and TCC models. Subsequently, the decisions for the intermediate years are made by FILLIN.

Optimization of Thermal Generation Mix by OPTMIX:

The OPTMIX model determines for each snapshot year the mix of non-peaking thermal units based on economics and operating constraints, given the thermal mix of the previous snapshot year.

The methodology of OPTMIX is a static optimization based on the annual thermal load duration curve and derated capacities. Discrete unit sizes

are considered. The scale effect is indirectly taken into account by the snapshot-year approach, if the load growth between two successive snapshot years is big enough to allow the installation of large units. The economic aspects are modeled by the screening curves and the technical constraints are reflected on the unit capacity factors.

The screening curve approach to determine the optimal mix when no technical constraints apply is shown in Figure 2.
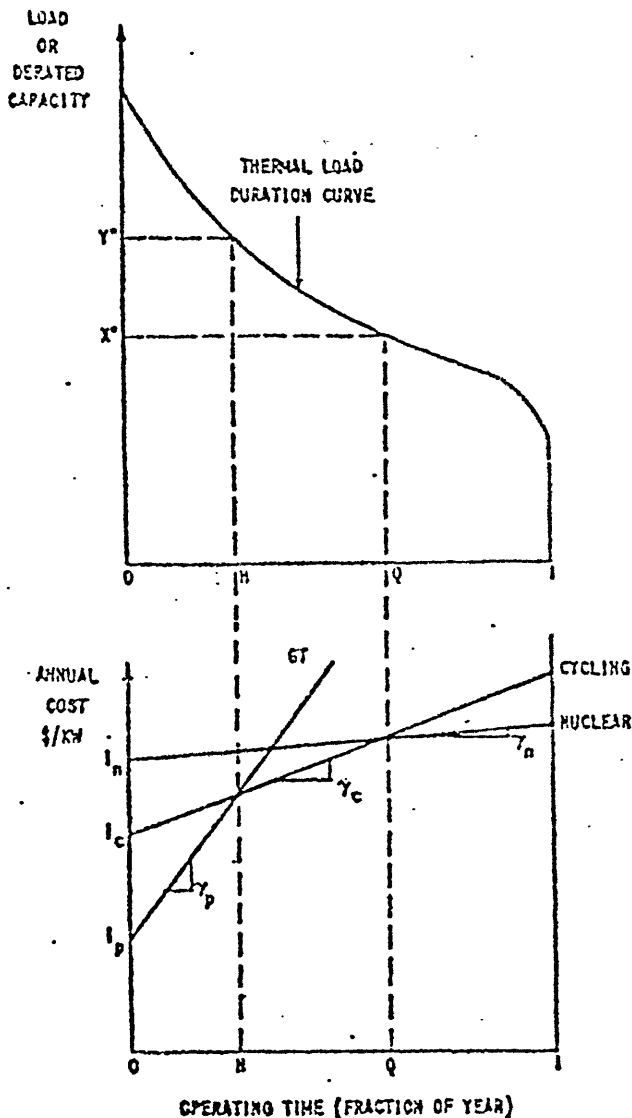
Figure 2. Screening Curve Approach to Determine the Optimal Thermal Generation Mix

Definitions:

C_p = Annual fixed cost (capital charge plus fixed O&M) of peaking units in $/kW.

γ_p = Operating cost of peaking units in $/kW-year at 8760 hours.

A_p = Availability of peaking units.

$I_p = (C_p/A_p)$ Effective annual fixed cost.

Similar notations are defined for base load and cycling units by changing the subscripts to "n" and "c", respectively.

The annual cost function of each kW of derated capacity is shown in Figure 2 as a straight line with a slope equal to the operating cost γ and an intercept equal to the effective fixed cost I. These screening curves combined with the annual thermal load duration curve demonstrate the economics of installing peaking units to serve the portion of the load with load factor less than H,

where $H = (I_c - I_p)/(\gamma_p - \gamma_c)$

Moreover, they show that cycling units should be installed to serve the load which occurs more than H% of the time up to the point where base-load units take over at load factor Q,

where $Q = (I_n - I_c)/(\gamma_c - \gamma_n)$.

The load levels which correspond to the load factors H and Q are denoted by Y* and X*, respectively. Making the assumption that derated capacities are equivalent to firm load levels, the value X represents the optimal amount of derated base load capacity, and

$(Y - X)$ = The amount of cycling capacity.

However, technical constraints can override the optimal conditions. For instance, there is a minimum capacity factor for nuclear units which prevents them from operating in a cycling mode. There may also be a maximum capacity factor for gas turbines above which their reliability becomes greatly impaired. These constraints modify X* and Y* to $\hat{X}$ and $\hat{Y}$.

An integer number of base-load units will be added to the existing ones, up to matching $\hat{X}$ within some tolerance. An integer number of cycling units will be added to the base-load units and the existing cycling units up to matching $\hat{Y}$ within some tolerance.

Peaking Capacity Planning by TCC:

Once OPTMIX has defined the non-peaking structure, the system security level can be estimated by a probabilistic calculation. This is done by computing a yearly Equivalent Load Duration Curve (ELDC) on the basis of the thermal load duration curve and the forced outages of all the non-peaking units. Then peaking units are added one at a time until the loss-of-load probability reaches the desired reliability level.

The thermal LDC can be based on 8736 hourly loads or 260 daily peak loads according to the selection of a reliability index. The impact of maintenance is approximated by valley filling the LDC with the MW-days of maintenance outages.

Interpolation Between Snapshot Years by FILLIN:

Given the new units which are to be installed between two snapshot years, and the linearly interpolated reserve requirements for the intermediate years, these new units are scheduled for installation according to the following criteria:

- The relative mix of the alternative types of new generation should be close to the target mix for each intermediate year. For example, if the target mix is 1.3 nuclear units in a particular year, the program will consider the possibilities of either one or two nuclear units.

- Of all the possible combinations of alternative types in each year, that combination which offers the least installed capacity and yet meets the reserve requirement will be selected.

The production costs for the intermediate years are obtained by PROCOX operating on the thermal load duration curve which is interpolated between the snapshot years and using the actual thermal system structure for these intermediate years.

Limitations

Because the expansion plan is the result of a series of static optimizations, it is not dynamically optimal. This fact limits the application of PUPS to really long-range studies for which the exact timing of unit installations is not so critical. However, combined with judgment, PUPS can still be used for near-term planning.

· Expansion planning with storage devices is not an automatic feature in PUPS. It requires the input of a storage expansion scenario. Similarly, automatic selection of new hydro units to be installed is not possible.

· The production costing method in PROCOX does not take into account accurately the effect of random outages. The effect of maintenance schedules on the production cost is also not modeled accurately. The derating procedure (by forced outage rate and planned outage rate) is only valid for large systems with many units. However, it may be argued that this approximation is acceptable if one only wants the cost differences between alternative expansion plans whose accuracy should be acceptable because the alternatives are developed by the same model with the same set of approximations.

Examples and Test Cases

No published example and test case are available. The program was used extensively in the Bay of Fundy Tidal Power Study for developing 25-year expansion plans with and without tidal power for two regions, the Canadian Maritime Provinces and the New England region. Typically, a snapshot interval of 5 years was used.

The expansion alternatives considered were nuclear, coal, combustion turbines and pumped storage.

Performance Capability

The program requires 57 K words or 230 K bytes of core storage.

For a test case with 7 snapshot years, 25-year expansion period, 40 generating units expanding to 120 units, 3 hydro units, and one equivalent pumped storage unit, the execution time on a UNIVAC 1108 computer was 90 CPU seconds.

APPENDIX F
MNI-GRETA - GENERATION PLANNING MODELS OF ELECTRICITE DE FRANCE (EDF)

Staff   Electricité de France

Scope

There are a number of models developed and used by EDF for long- and medium-term generation and transmission planning. Two models are described here, GRETA and MNI. They are not directly integrated into a single computer program. Two other models, DYNA and MEXICO, are used for transmission planning. Each of the four models addresses a sub-problem of the global generation and transmission planning problem, as follows:

- MNI for long-term generation planning

- GRETA for medium-term production costing and adjustments to the long-term expansion plan

- DYNA for long-term studies of plant location and transmission network development

- MEXICO for medium-term studies of the transmission network reinforcements

For long-term studies, dynamic models (MNI and DYNA) are used. MNI uses optimal control methods while DYNA is a linear program encompassing all the years in the study period. For medium-term studies static models (GRETA and MEXICO) are used, resorting mainly to Monte Carlo simulations for annual analysis. For the interactions between these models, see Figure 1.

This synopsis will describe the MNI and GRETA models only.

Objective

The objective of the MNI model is to minimize the total present worth of investment, expected production cost and cost of unserviced energy, discounted at a given rate over several decades. Predicted equipment and fuel prices are entered as deterministic data, while load, hydraulic inflows and forced outages are treated as random variables. The objective function is:

$$\text{Min} \sum_{t=1}^{\infty} \left(\frac{1}{1+d}\right)^t * \left[G_t(x_i^t) + \sum_i K_i \upsilon_i^t\right]$$
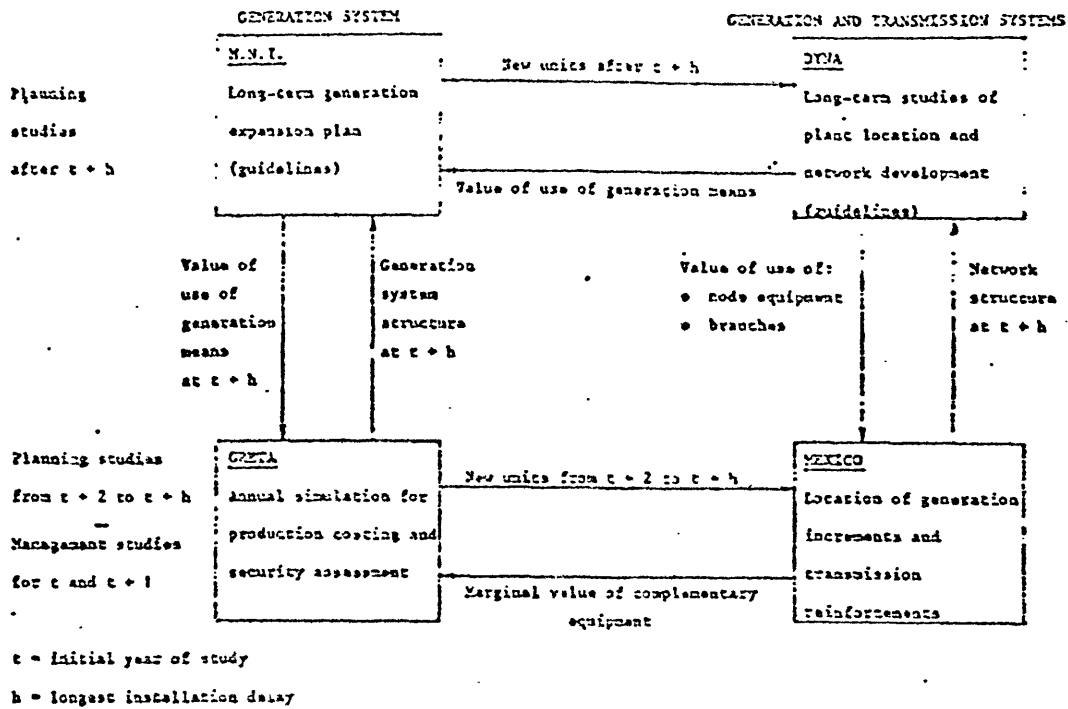
Figure 1. Decomposition of the Planning Problem into Subproblems for Suboptimization

subject to:

$$\underline{U_i^t} \leq U_i^t \leq \overline{U_i^t}$$

$$X_i^{t+1} = X_i^t + U_i^t$$

$$X_i^0 = \text{Initial state (known)}$$

where d = Discount rate

K_i = Annual investment cost associated with class i (constant annuities and replacement by same type at end of lifetime)

U_i^t = Capacity investment in class i made in year t

$G_t(X_i^t)$ = The expected production cost during year t given the system structure X_i^t in that year. The failure cost is also included.

The production cost G_t is estimated from a sub-model within MNI which is different from GRETA.

This sub-model is actually a production costing

model incorporating the failure cost through a fictitious expensive unit loaded after the last unit in the system. The objective function is to minimize the expected annual production cost.

$$\text{Min}_{M^t, R^t} \quad Z = \sum_h P_h \sum_j P_j \sum_{t=1}^{12} Z_t (M^t, R^t, H_h^t, L_j^t)$$

subject to:

$$\underline{M_i} \leq \sum_t M_i^t \leq \overline{M_i}$$

$$\underline{R^t} \leq R^t \leq \overline{R^t}$$

where M_i^t = Maintenance status of unit i in month t

R^t = Hydro release during month t

H_h^t = Water inflow with probability P_h

L_j^t = Load level with probability P_j

Z_t = The monthly production cost if random variables are H_h^t and L_j^t and decision variables are M^t and R^t.

The objective of GRETA is to simulate the optimal operation of a power system which contains hydro and storage devices, taking into account the uncertainty of load, thermal generation and water inflows. It is an accurate model suitable for short-term and medium-term planning. Because of its computational requirement, it cannot be directly integrated with the MNI model for generation capacity planning.

Constraints

In the MNI model, the constraints on the optimization are expressed as upper and lower bounds on the admissible generation additions for each generation alternative.

A significant departure from the U.S. practice is the absence of reliability constraints. Reliability is considered as part of the cost function. A failure cost is computed for the expected unserviced energy and added to the generation fuel and operating cost. Usually this failure cost per kWH is assumed to be $0.50 to $1.50.

In the GRETA model, the hydro system is represented by three equivalent units with a limited capability to model their interactions. Operating constraints are ignored. Storage devices are constrained by their reservoir volume.

Method of Solution

The MNI long-term expansion problem is formulated as an optimal control problem using Pontryagin's maximum principle. It is solved by a steepest-descent algorithm.

This approach permits a timewise decomposition in which co-state variables (in the context of Pontryagin's maximum principle) play an important role and provide useful information. A component ψ_i^t of the co-state vector is the value of use of equipment i at year t, i.e., the present worth of expected cost reduction if 1 kW of equipment i is added to the system in year t.

GRETA is a production costing and security assessment model which performs Monte Carlo simulations for the three random variables (load, thermal capacity and water inflows) and applies management/ operating rules to determine annual statistics on the system operation.

In a sub-model of GRETA called PRODY, dynamic programming is used to provide optimal hydro management rules which can be used for an efficient simulation of the hydro system.

Production Decisions

In the MNI model, production decisions are made under a number of assumptions to increase the computational efficiency. On the other hand, the GRETA model examines the effect of uncertainty much more accurately at the cost of computer time.

Production Costing in MNI:

The maintenance schedule M^t and the hydro release R^t are optimized decision variables in the problem formulated earlier. Given these energy management decisions, the production costing problem is solved on a monthly basis by deterministic analyses repeated for several occurrences of the random variables (load and water inflows).

The load model is a monthly duration curve with 10 levels corresponding to well-known periods:

- Levels 1, 2, 3, and 4:   on-peak periods of work days

- Level 5:   on-peak periods of Saturdays

- Levels 6 and 7:   off-peak periods of work days (night)

- Levels 8, 9, and 10:   remainder of weekends

This subdivision is adopted for easier scheduling of storage devices.

The thermal units are represented by their derated capacity and a single proportional cost (incremental cost).

The hydro units are aggregated into a single equivalent unit, and for each water inflow value and each water release decision, the maximum amount of energy W_1, W_2, ...W_{10} which can be used during each level of the LDC are determined.

The storage units are aggregated into two equivalent units: one with a daily cycle and the other with a weekly cycle operation. Both units are characterized by:

- Capacity P

- Round-trip efficiency η

- Reservoir volume V

The generation schedules for the various units are determined by an iterative process whose objective is to determine the optimal pumping schedules given the hydro capability and the thermal cost function:

STEP 1:   Select a marginal pumping cost λ_p

STEP 2:   Determine optimal pumping schedules for λ_p. This is solved by linear programming.

STEP 3:   Given the energy stored, optimize the hydro and restitution schedules (i.e., level out the thermal load.) This is a nonlinear program with linear

-36-

constraints. As a result, the marginal saving from restitution is known: λ_r

STEP 4: Compare λ_r and λ_p to determine whether pumping should be increased or decreased. Adapt λ_p accordingly. Go to STEP 1.

Note that in this production costing model, only load and hydro uncertainties are considered. Thermal forced outages are represented by capacity deration. Load and hydro uncertainties are treated by a combinatorial approach: computations are repeated for selected combinations of loads and water inflows to represent their full spectrum of occurrence and the results are weighted according to the assocaited probabilities.

The production costing model also determines the cost gradient vector with respect to all capacities of equipment considered (thermal and storage). This result is useful for the "investment" model which can use them as initial gradients (values of use).

Production Costing by GRETA:

The load model considers an annual energy level (specified as data), weekly energy levels for average weather conditions (Gaussian distributions with autocorrelation with the two preceding weeks), and daily weather impact (modeled through load-weather model and weather statistics).

The hydro system is aggregated into three equivalent hydro units (total equivalent capacity less than actual capacity), with a limited number of parameters to represent their interactions. (See Figure 2.)
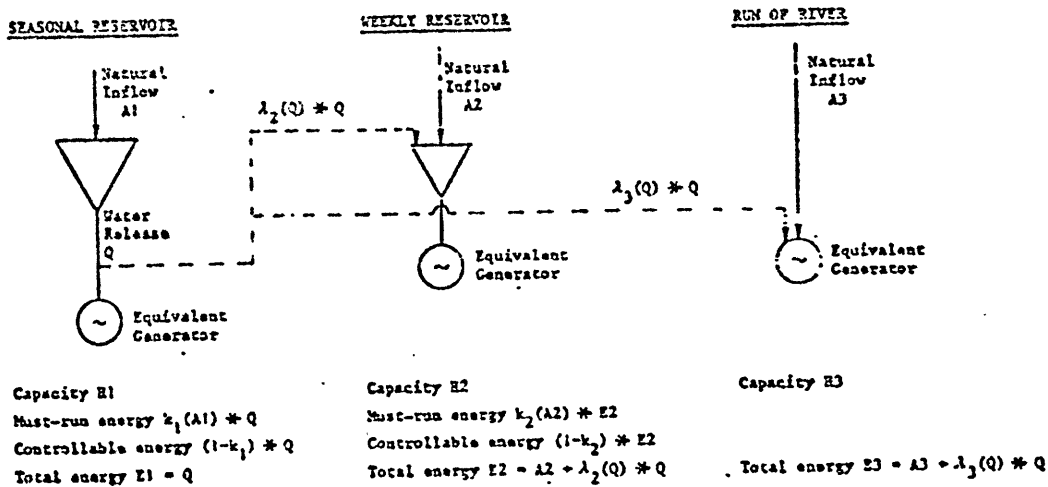
The storage system is aggregated into two equivalent units (weekly and daily cycle). No seasonal storage is considered. Each unit is defined by pumping and generation capacities, reservoir volume and round-trip efficiency. Their scheduling is done on the basis of the weekly LDC after deduction of the hydro contribution (in a former version), or by optimization in the current version.

The thermal units are considered individually except for old units which are aggregated. They are defined by their capacity, average production cost and reliability data (steady-state forced outage rate and average duration of outages). The last thermal unit has a very high cost and is used to represent the cost of outages. Startup costs are neglected. Spinning reserve is not mentioned.

The maintenance schedule is prespecified but the optimal hydro management rules are determined by the model itself. Unit commitment is not considered on an hourly basis; rather, it is approximately handled in the weekly load duration curves.

The model is actually a package of five programs: CONS, THALE, HYDRAU, PRODY and GRETA, which performs separate functions as follows:

GRETA: HYDRO SYSTEM REPRESENTATION FOR EACH WEEK

Capacity B1
Must-run energy $k_1(A1) * Q$
Controllable energy $(1-k_1) * Q$
Total energy E1 = Q

Capacity E2
Must-run energy $k_2(A2) * E2$
Controllable energy $(1-k_2) * E2$
Total energy E2 = A2 + $\lambda_2(Q) * Q$

Capacity E3

Total energy E3 = A3 + $\lambda_3(Q) * Q$

NOTE:

Q is a decision variable.

All other quantities are data.

Figure 2. GRETA: Hydro System Representation for Each Week

CONS: CONS reads elementary load information and prepares load data samples by Monte Carlo draws. Autocorrelation and weather effect are modeled.

THALE: THALE reads characteristics of thermal system and maintenance schedules. Samples of available thermal capacity are drawn by Monte Carlo methods, using state probabilities depending on previous state only (Markov assumption, Kolmogorov equation).

HYDRAU: HYDRAU reads hydro system data and hydro inflows historical data. It defines the three equivalent hydro units (one seasonal, one weekly, one run-of-river) and the inflow sample by Monte Carlo draws or by selection of past sequences. Functions are specified for defining the must-run energy from seasonal reservoir according to the water inflow, and the fractions of seasonal release which increase the downstream energy.

PRODY: PRODY uses dynamic programming to define optimal hydro management rules.

The flowchart in Figure 3 shows the three basic steps. The following definitions of variables are needed:

R_t = Water reserve at beginning of stage t

A_t = Water inflow during stage t. This is a random variable with the following probability mass function:

$$\text{Prob (inflow} = A_{it}) = \Pi_{it}$$

Q_t = Water release during stage t (in MWH)

$G_t(Q_t)$ = Thermal saving in stage t resulting from optimal utilization of release Q_t.

$V(R_t)$ = Value function of water reserve R_t is defined as expected savings generated by optimally managing the system from time t on with R_t as initial reserve.

By its definition, $V(R_t)$ can be written as:

$$V(R_t) = \max_{Q_t} \left\{ G_t(Q_t) + E\left[V(R_{t+1})\right] \right\}$$

The expectation is taken over the random water inflow distribution.

The optimal water release is obtained by imposing:

$$\frac{dV(R_t)}{dQ_t} = 0$$

From this, one derives the following optimal condition:

$$G_t'(Q_t) = E\left[V'(R_{t+1})\right]$$

where the ' denotes a derivative w.r.t. the explicit variable.

The thermal savings $G_t(Q_t)$ are determined by peak shaving the load duration curve, from which $G_t'(Q_t)$ can be computed.

The curve $V'(R_{t+1})$ can be derived by the following backward recursive process:

$$V'(R_{t+1}) = V'(R_t - Q_t + A_t)$$

$$E\left[V'(R_{t+1})\right] = \sum_i V'(R_t - Q_t + A_t) * \Pi_{it}$$

For a fixed (known) value of R_t, $E\left[V'(R_{t+1})\right]$ can thus be expressed as a funtion of Q_t if $V'(R_{t+1})$ is known. Remember that $V(R_{T+1})$ is assumed to be known; its derivative $V'(R_{T+1})$ can thus be obtained easily in order to initialize the backward recursive process.

Knowing the curve $E\left[V'(R_{t+1})|R_t\right]$ as a function of Q_t and the curve $G_t'(Q_t)$, the optimal Q_t will be obtained at their intersection. Also, the ordinate of their intersection is the marginal value $V'(R_t)$ which can be associated with the reserve R_t given the optimal decision Q_t^*.

The entire solution algorithm can, therefore, be summarized as follows:

1   Start with t = T

2   Determine $G_t'(Q_t)$

2a   Select one value of R_t

● Select one value of Q_t

● Compute $E\left[V'(R_{t+1})|R_t\right] = \sum_i V'(R_t - Q_t + A_{it}) * \Pi_{it}$

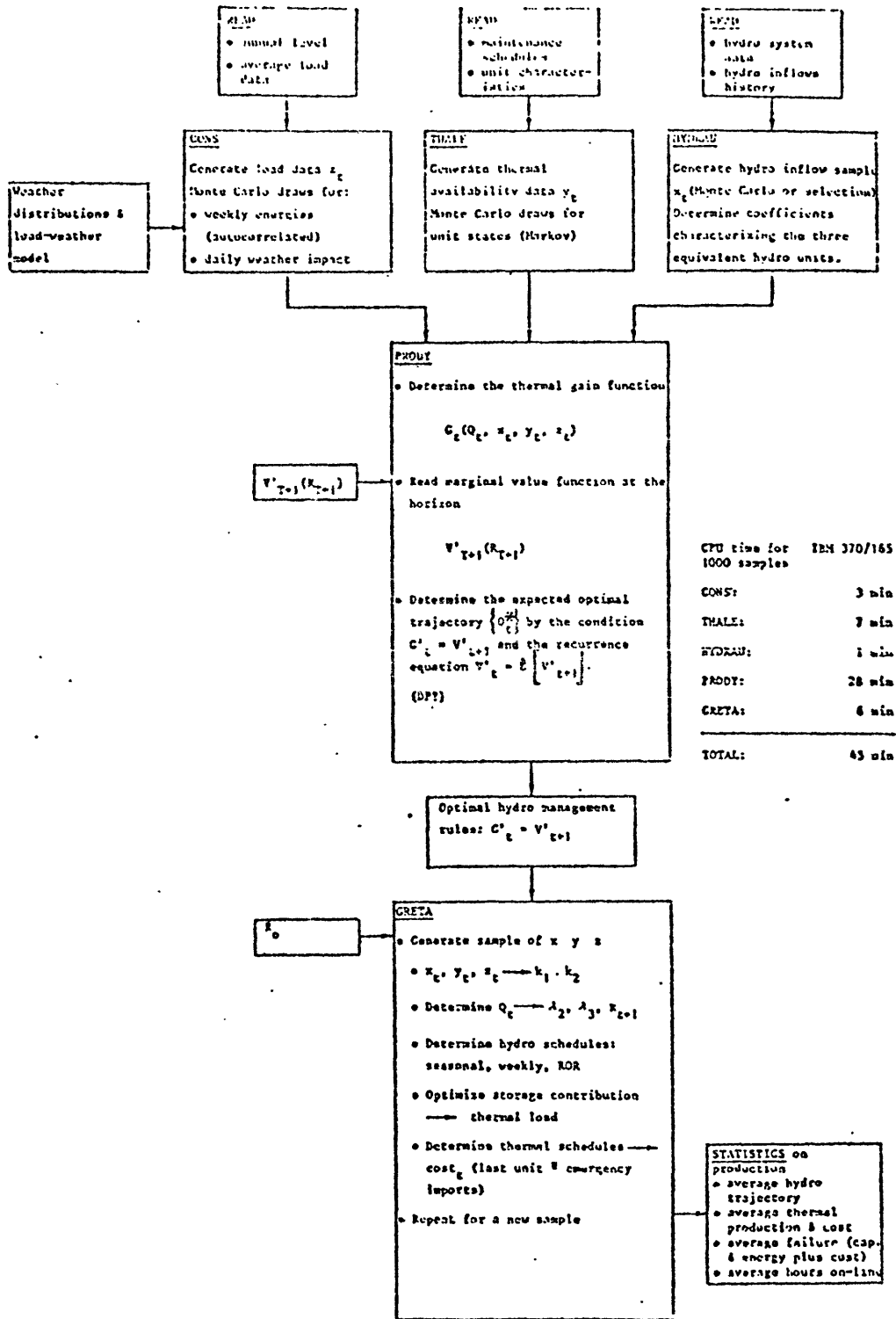● Repeat for various Q_t

● Determine Q_t^* and $V'(R_t)$.

Figure 3. Flow Chart of GRETA

Appendix B

MEETING NOTES FROM UTILITY INTERVIEWS UNDER TASK I

ANALYSIS OF UTILITY REQUIREMENTS

The meeting notes which follow summarize discussions held with nine
utilities between October 17, 1979 and January 8, 1980 concerning
assessment of the tools currently in use for capacity and financial
planning, the proposed structure of the EGEAS system and additional
requirements or emphases required of the EGEAS structure. In each
instance the format used in the discussion was the same (see attached)
with the meeting beginning with a description of the activities under
way at MIT and Stone and Webster in the development of EGEAS. The
discussions then continued in an open format to cover present activities
in model development within the utilities and/or models currently being
used for utility planning.

The meeting notes which follow do not contain materials, generally
available from the utilities themselves, which were collected in those
meetings. References to these materials have been left in the text to
allow the reader to contact the utility should such materials be of
specific interest.

PROPOSED UTILITY NEEDS INTERVIEW AGENDA

EPRI/EGEAS

I. Introduction to Purpose of EGEAS

Purpose: Develop a modular and flexible, state-of-the-art software
          system for electric utility generation planning, operating
          from a common data base

Based upon: GEM, developed at MIT
             OPTGEN, developed at SWEC

Advantages of proposed EGEAS structure:

    o capable of being made fully interactive
    o flexible options in level of detail, generation alternatives
       and load management techniques
    o sufficiently flexible to allow for addition of other
       specific modules as might be required in the future
    o advanced handling of uncertainties

II. Proposed EGEAS model structure

Model Structure

    - linear programing
    - dynamic programing
    - Benders' decomposition
    - static year end optimization
    - prespecified capacity expansion path

Load Representation

- loading trapezoid
- Booth Baleriaux
- for storage analysis, short time sequence chronological checking
  system

Reliability Analysis

- loss of load probability
- loss of load hours
- energy not served

Advanced Features:

environmental/siting
interconnections
uncertainties
new technologies and load modification
preliminary analysis of financial/regulatory/environmental
    modeling requirements

B-2
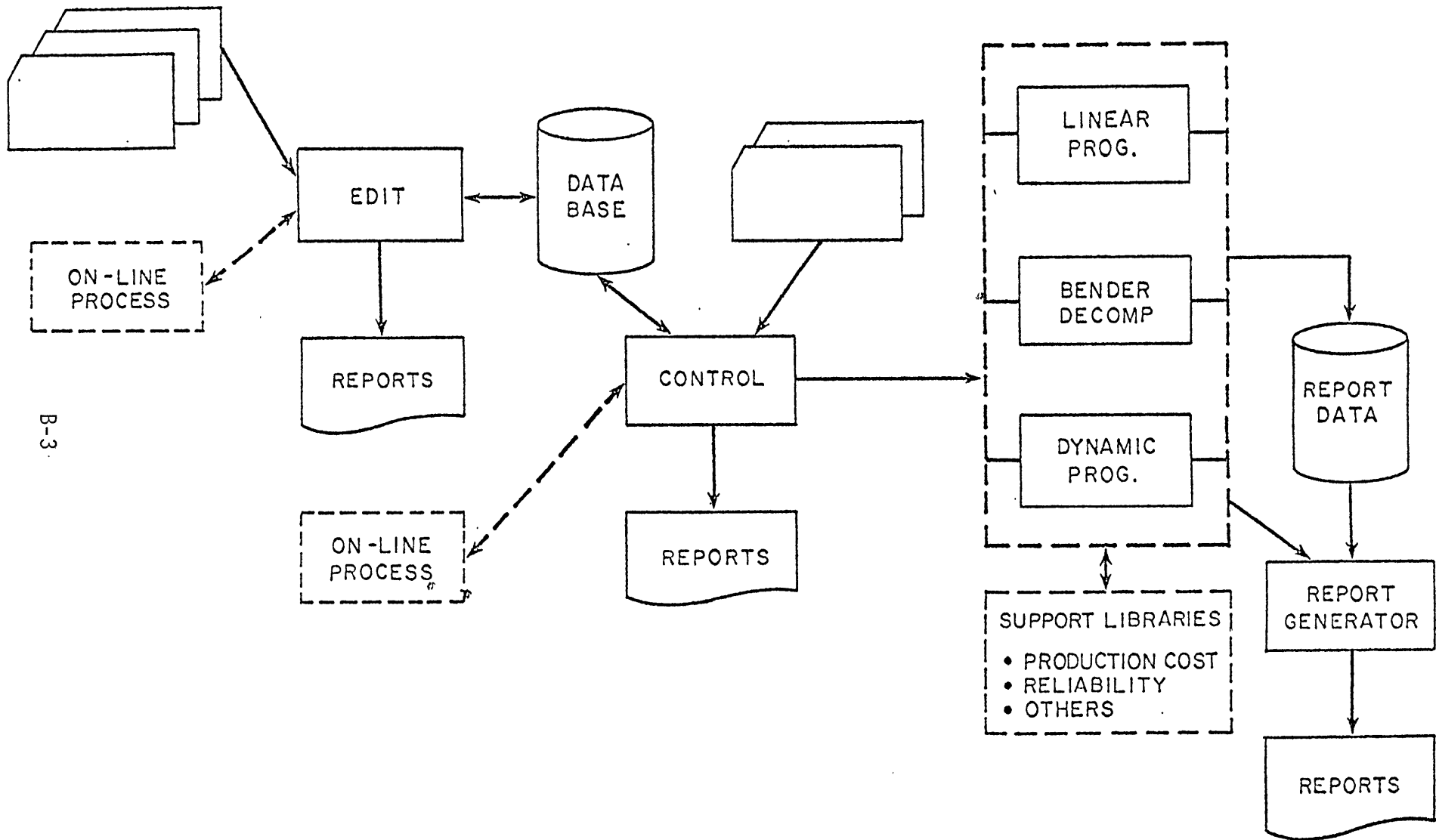
Proposed Structure from Proposal

IV. Discussion with Host Utility of:

    A. Capacity Expansion Planning Models/Methods currently in use
    B. Operating System Models in use
    C. Financial Planning Models currently in use
    D. Interactions between the above
    E. Methods used for sensitivity/uncertainty analyses

V. Useful Additional Capabilities Beyond Those Currently Available and/or Those Proposed by EGEAS

NOTES OF CONFERENCE

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM
ELECTRIC POWER RESEARCH INSTITUTE

Held in the offices of
Arizona Public Service Co.
Phoenix, Arizona

October 17, 1979

Present for:

Arizona Public Service Co. (APS)   Mr. Gian Khubchandani
                                          Supervisor of Corporate Models

                                          Mr. Gerhard Steinbrenner*
                                          Manager of Systems Development

                                          Mr. Vince Converti*
                                          Manager of Computer Services

Massachusetts Institute of   Dr. Richard D. Tabors
Technology (MIT)   Manager of Utility Systems Program
                                          (Principal Investigator)

                                          Mr. Edward J. Moriarty
                                          Research Staff
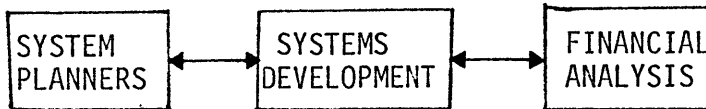
PURPOSE

Task 1 Analysis of Requirements - First Meeting

The purpose of this meeting was to identify the basic capacity expansion planning analytical needs and current modeling capabilities of APS, and to solicit information, experience and recommendations relating to the proposed EGEAS structure.

*Not present for entire meeting.

B-5

SUMMARY OF DISCUSSION

1. M.I.T. presented a discussion of the EGEAS goals and proposed structure (see attachment).

2. APS discussed the models it is currently using or developing and way in which the system planners and financial anlysts utilize the analysis support group within APS.

a. APS has a Systems Development Department which is used by both planners and financial analysts.

```
┌──────────┐       ┌──────────┐       ┌──────────┐
│SYSTEM    │◄─────►│SYSTEMS   │◄─────►│FINANCIAL │
│PLANNERS  │       │DEVELOPMENT│       │ANALYSIS  │
└──────────┘       └──────────┘       └──────────┘
```

b. APS uses GE's Optimized Generation Planning Model (OGP) and has an in-hour producton costing (PC) model. Currently APS is developing an in-house expansion planning model.

c. APS uses a "pre-specified expansion schedule/simulation." approach and does not currently use the mathematical optimization subroutine in OGP for analyzing various generation expansion scenarios.

d. APS has an in-house corporate finance model which is based on the GPOSII model developed by PLANMETRICS. Their contact is:

Gary Ganz, V.P.
Planmetrics, Inc.
5320 Sears Tower
233 South Wacher Drive
Chicago, IL   60606
(312) 876-2700

This model has been used by San Diego, New Jersey, and others and is a good general purpose operating system.

e. Currently, APS does not have any direct modeling or analytic links between financial analysis and system planning analysis.

3. APS had the following concerns/evaluation of EGEAS:

a. Hour-by-hour P.C. is too costly for 20-30 years expansion planning but analysis based strictly on monthly or yearly load duration curves is not adequate for addressing some important issues. Need to find trade-off point.

b. Different optimizations cannot be expected to yield similar results. However, it must be possible to explain any differences between optimization results.

c. There was concern about the scope of work extending from research through production software in a single effort (these concerns were allayed by a brief discussion by MIT of the project structure/schedule and the role of Stone and Webster).

d. Better representation of financial considerations should be incorporated into capacity planning models. Better interfacing between capacity planning and financial models should also be allowed for.

e. Programs should be able to handle multi-area considerations.

f. The financial representations within the Over-Under model should be considered. (APS has had some problems in obtaining useful documentation for running Over-Under.)

g. The ability to find dollar cost to the consumer of Environmental Regulation (e.g., Clean Air Act) would be useful, but in-depth environmental analysis would not be feasible due to prohibitive data requirements.

NOTES OF CONFERENCE

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

ELECTRIC POWER RESEARCH INSTITUTE

Held in the offices of
Niagara Mohawk Power Corporation
Syracuse, New York

October 31, 1979

Present for:

    Niagara Mohawk Power Corporation (NMPC)   Mr. P.D. Raymond
    Manager - Engineering Planning

    Stone and Webster Engineering Corp.   Mr. K.L. Hicks
    (SWEC)   Supervisor - System Planning

    Massachusetts Institute of   Dr. F.C. Schweppe
    Technology (MIT)   Professor - Electrical
    Engineering

    Dr. R.D. Tabors
    Manager - Utility Systems
    Program
    (Principal Investigator)

    Mr. E.J. Moriarty
    Research Staff

PURPOSE

Task 1-A Analysis of Utility Requirements

The purpose of this meeting was to discuss the present and planned expansion, operating and financial modeling capabilities and practices of Niagara Mohawk, and to solicit information, experience and recommendations relating to the proposed EGEAS structure.

SUMMARY OF DISCUSSION

1 - MIT presented an overview of the EGEAS goals and proposed structure
     (see attachment).

2 - NMPC requested further information on environmental aspects of the
     EGEAS project, especially the nature of our dependence on the NRC
     project. MIT stated that:

o   NRC had approved funds—so Phase II of the project should start soon.

o   The EGEAS contract states that EGEAS must be able to interface with
     the Phase I methodology—and thus does not depend on future work to
     be done in Phase II.

MIT then discussed the concept of generic siting, its inclusion in the
Linear Programming component of EGEAS, its usefulness in terms of linking
with "area siting" as proposed in the Phase I methodology and its
usefulness in standalone capacity planning studies (i.e., with no
independent area siting optimization). (For example, a use in studying
the effects of non-attainment issues on capacity planning.)

3 - NMPC requested information on the status of GEM's code. MIT then
     presented the history of GEM's development, and stated that
     currently, the GEM LP is a working but undocumented tool, that
     SYSGEN is well documented and available, that the environmental
     screening models would have to be further developed and tested
     though this is not within the scope of this project. MIT then
     stated that the decomposition technique upon which GEM was
     originally designed would not converge to a single optimal solution
     but that the structure of the data base and code were such that the
     prototype model used in Bloom's thesis was able to be written,
     installed, and tested with a relatively minor amount of work (~ 2-3
     months).

4 - NMPC raised the question of who would maintain the EGEAS software
    after the project concludes. MIT will definitely not do it. The
    question is more between EPRI and SWEC and should be discussed
    during the January Review Meeting.

5 - NMPC asked how flexible the code will be. MIT stated that the
    GEM-based code will be fairly flexible and cited some examples to
    substantiate this. SWEC stated that the OPTGEN code is not very
    flexible primarily due to the nature of dynamic programming.

6 - Discussion then focused on the planning/financial practices and
    tools at NMPC.

o   Pool level planning first determines the needed capacity to meet a
    22 percent margin (1 day in 10 years LOLP) assuming ties [40 percent
    united].

o   NMPC is required to meet an 18 percent margin (1 day in 10)

o   Once the reliability of the current/committed system is analyzed for
    each year of the planning horizon then GE's OGP No. 5 model is used
    to determine the best capacity addition schedule and mix.
    Transmission studies are then performed.

o   NMPC's primary focus is on detailed production cost analysis used to
    confirm/fine tune the OGP results.

o   NMPC uses PROMOD-3, developed by Energy Management Associates (EMA)
    in Atlanta (a wholly onwed subsidiary of Planmetrics in Chicago) for
    its production cost analysis. PROMOD is used on average once a
    night. Operating people also use PROMOD.

o   The pool is currently in the process of installing EMA's multi-area
    PROMOD.

o   The New York "Siting Guide" states that the best site should be used
    regardless of service area. Joint ownership is, of course, current
    standard practice. Thus the Environmental Commission of the N.Y.
    Planning Pool and the PUC are identifying sites (> 2000 MW) and
    rating them. No trouble has been found with increasing land values
    due to the large number of sites identified and to the absence of a
    need for near-term expansion.

o   NMPC's current plans include (through 1992)

    -   Oswego 6 (Sister unit ≯ $240/kW!!!) – oil in December – joint
        with Rochester

    -   Nine Mile Nuclear – 1 year away – multiple owners under NMPC.

    -   Either one of: Sterling (NUC or COAL) ~ 1988/90 or a Lake Erie
        coal site.

o   NMPC does not have a "corporate model." Currently it uses a "Bottom
    up" financial model in which interest rates, $ to stockholders are
    input and the model determines the rates—and gets coverage ratio.

o   NMPC is looking at Planmetrics for a financial model.

o   Long Island Lighting is developing a "Bottom up" financial model for
    engineers. Contacts: John Weismantle
                            Tony Nosselelo (sp)

o   NMPC has recently installed the Over Under Model.

o   The financial and planning people at NMPC have a good working
    relationship.

7 – NMPC expressed interest in the new technology (fuel cells, small
    hydro, gasifier combined cycle, fluidized bed)* aspects of EGEAS.

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*See EPRI 991, Gildersleeve.

8 - NMPC is also interested in the trade-off between distributed and central generation and the associated impact on investment in transmission.

9 - The level of user sophistication was discussed. Whereas a technician will be able to actually run the model, qualified, experienced planners will be required to ensure proper use of the model. The idea of having training seminars was also discussed.

10 - The nature of the financial handling in EGEAS was discussed. NMPC feels that it must be addressed. The concern was expressed that a running model's bias toward large capital investment options must be mitigated by some representation of the difficulties in financing such options. The feasibility of using annualized fixed-charge rates was discussed. There is not much gain over levelized fixed charge rate unless yearly cash flow constraints (or something equivalent) are used since the objective function is simply present worth of revenue requirements (which does not in itself capture timing considerations).

11 - Discussion then focused on the uncertainty issues. MIT discussed the two fundamentally different types of uncertainty (i.e., that of input assumptions and that of changing conditions after some decisions have been made in the planning process). NMPC feels both are important. NMPC feels uncertainty in load projections and in construction delays must be able to be addressed.

12 - For testing EGEAS NMPC feels that synthetic systems will be adequate, but that comparison runs should be made with OGP at some point since it is available and used by EPRI.

13 - For NMPC, hydro will be base only. The representation of hydro as currently proposed in EGEAS will be adequate.

NOTES OF CONFERENCE

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM
ELECTRIC POWER RESEARCH INSTITUTE

Held in the offices of
Pacific Gas and Electric Company
San Francisco, California

November 7, 1979

Present for:

Pacific Gas and Electric Co. (PGE)	Dr. George Gross Engineer - Computer Application Department
	Mr. Richard Albert Engineer - Generation Planning Department
Electric Power Research Institute (EPRI)	Dr. Neal Balu Electrical Systems Division (Project Manager)
Stone and Webster Engineering Corporation (SWEC)	Mr. Kenneth L. Hicks Supervisor - System Planning
Massachusetts Institute of Technology (MIT)	Dr. Fred C. Schweppe Professor - Electrical Engineering
	Mr. Edward J. Moriarty Research Staff

PURPOSE

Task 1-D Review of Other Models

The purpose of this meeting was to discuss the present and planned expansion, operating and financial modeling capabilities and practices of PGE, and to solicit information, experience and recommendations relating to the proposed EGEAS structure.

SUMMARY OF DISCUSSION

1 - M.I.T. presented an overview of the EGEAS Goals and Proposed
Structures (see attachment one).

2 - PGE expressed concern about the EGEAS framework in that more than one
optimization technique could be selected by the user. The primary
concerns were that EGEAS was being designed to be all things to all
people and that the project may indeed be overambitious. Also, since
the different otpimization techniques are based on different assumptions,
PGE thought that this would be very confusing to the normal user.
Further, PGE questioned the level of sophistication required of EGEAS
users in general.

M.I.T. agreed that the development of the EGEAS package as proposed would
take a considerable amount of development effort, but that we were
definitely not starting from ground zero. Only one of these proposed
optimization techniques requires any real theoretical development (the
Benders' Decomposition). The other optimization techniques are based on
programs which have already beeng written at M.I.T. and Stone and Webster
and require no real theoretical development. Further, the reasons for
having the multiple optimization techniques as options were not an
attempt to be "all things to all people," rather, the design of the
system was based specifically on the needs of an electric utility system
planner (not corporate modelers, regulators, etc.). Multiple techniques
allow for flexibility, varying levels of detail, and tailoring of
assumptions to best fit the nature of the different problems facing the
utility planner.

M.I.T. stated that the varying assumptions implied by the different
techniques would require a fairly sophisticated user, but that supply
only one optimization technique would not require any less sophisticated
a user. In other words by providing only one technique and thus only one
set of basic assumptions an unsophisticated user would tend to apply this
tool and analyses where the assumption may not be valid. It was agreed
that EGEAS should in some way emphasize the nature of the different

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assumptions associated with the different techniques for the user, and that the idea of a detailed training session/seminar or increasing the level of sophistication of the user should be investigated.

M.I.T. stated that EGEAS is not an optimization package, rather that optimization is used as a tool within the EGEAS framework. The role of the utility systems planner is becoming less and less one of finding the optimal solution, and gradually becoming more of finding a feasible solution, one that fits within the constraints of the varying interfaces with the planning problem, such as financial, environmental, etc.

3 - Attachment 2 is a flowchart of the current PGE planning process. A load forecast in terms of a peak, energy, and load-shape model is given to the Expansion Planning Department. Reliability analysis is performed on the current and committed system given the anticipated load. Required capacity additions are then determined using the one day in ten year LOLP, a minimum reserve of 12 percent, and a contingency that the system must be able to support a loss of the two largest units. An expansion schedule is then determined "by hand" since the number of choices is limited and since the major issues are those involved with the constraints on the system, for example, siting issues, lead time, fuel use act. The planning horizon required by the PUC is roughly ten to twelve years, which corresponds to the longest lead time which could be expected for a plant. For studies beyond the planning horizon required by the PUC, generic alternatives (base capacity, mid-range, peaking) are used for the analysis. Once and expansion schedule has been determined it is then given to the corporate modeling department. So far the financial constraints have not yet proved binding but they are certainly coming under scrutiny.

4 - PGE then described the models used in the various analyses. For reliability analysis an in-house model which develops a monthly capacity outage table and then checks daily peak loads for a year is used. This is a relatively standard reliability analysis. The production cost tool used currently, GRATE, is an in-house model which has taken two years to development and has been used for roughly three months.* It is a

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*A meeting was scheduled for November 8 between Dr. Gross and Mr. Moriarty to discuss the hydro handling of GRATE in more detail.

Booth-Baleriaux type of analysis, which can handle hydro, pumped hydro, purchases as well as the thermal system dispatch. Hydro in this model is dispatched along with thermal units and is not just treated as a load modifier. PGE has about seventy hydro plants, but these are modeled as eight equivalent hydro plants in this model. Hydro allocation is an input since it is far too complicated a matter to be included in a production cost simulation program. The corporate model used is also an in-house program which is basically a quick, deterministic bookkeeping system.

5 - PGE then raised a question about the ease of use of programs such as EGEAS. M.I.T. then stated that EGEAS was designed to ease the problems of the system planner in performing analysis and some of the ways which it would do this would be: (1) having a structured data base from which to perform analysis, and (2) having well-defined interfaces between the optimization techniques and the external analyses which impact on the expansion plan.

6 - M.I.T. then presented the concept of generic siting and told of the types of analysis which could be performed with such an approach (for example, non-attainment issues). PGE felt that this type of analysis may be useful to them.

7 - PGE then asked about the way in which cogeneration could be handled in EGEAS. M.I.T. responded that if the primary use is indeed steam production, then it could be handled as a load modifier. M.I.T. stated that further research would have to be done on the cogeneration issue before any further modeling approaches could be develodped.

8 - Discusssion then centered on the financial aspects of the EGEAS system. PGE's corporate model uses annualized fixed charge rates as do most financial models. Only if something like cash flow constraints are to be incorporated into the optimization, should annualized fixed charge rates replace the levelized fixed charge rates, as found in most planning packages. In these models, all costs are present worthed, thus anualized information is lost in the process. PGE thought that financial handling

which is more than that done in the Over/Under model would probably not be necessary. Stone and Webster stated that an important feature of the OPTGEN package, which is the dynamic programming basis for EGEAS, is that it uses integer plant values as decision variables as opposed to continuous variables in the LP and decomposition techniques. This is important from a financing point of view since the large blocks of capacity must be installed in various years, whereas with linear programming small portions of a type of plant could be installed in every year exactly following the load growth. Financial considerations are much more severe when studying blocks of capacity as opposed to incremental additions.
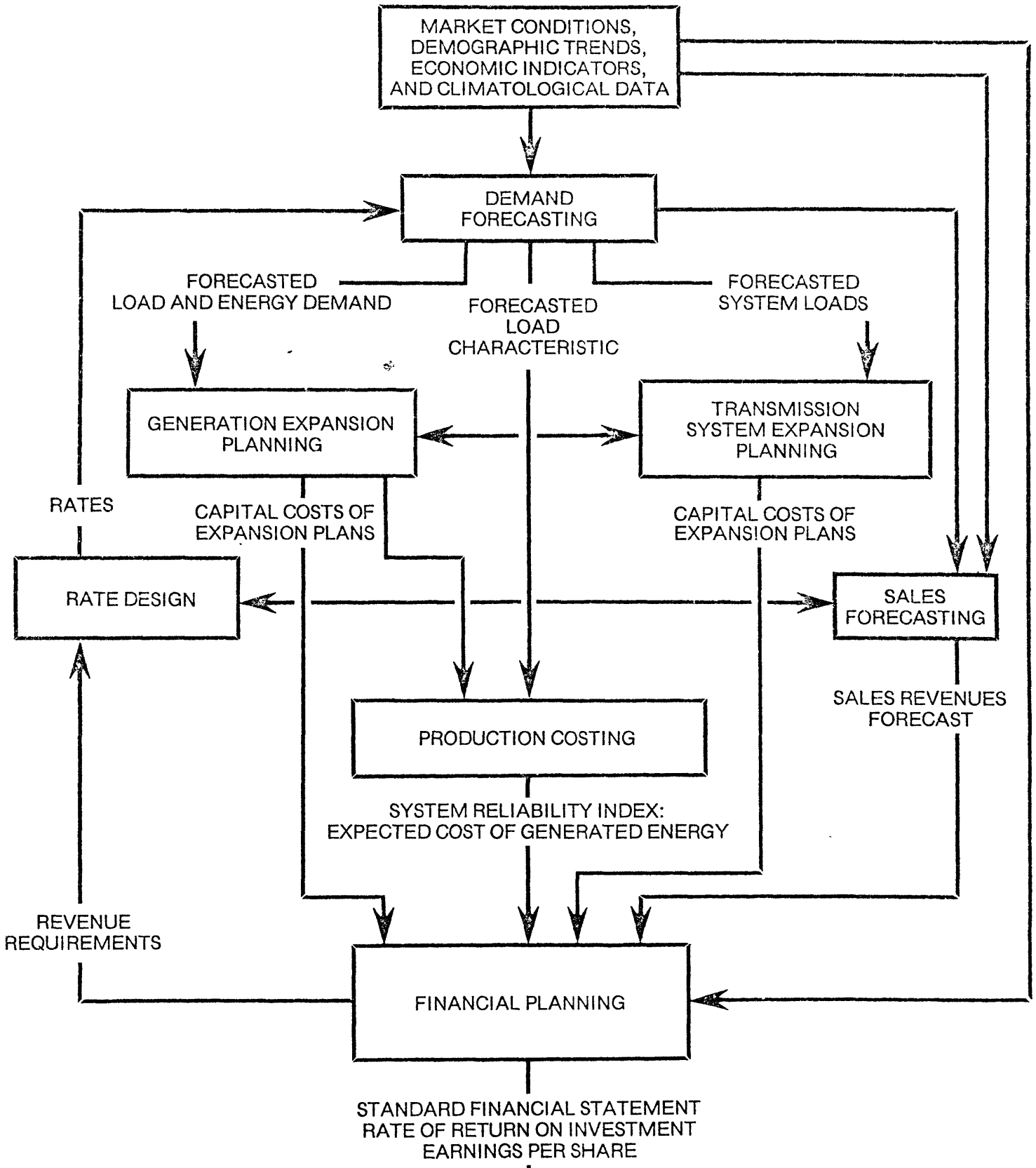
9 - PGE then expressed concern over the way in which end effects would be handled in EGEAS, since this can have drastic impact on the results of an optimization. M.I.T. agreed that end effects did play an important part in the optimization and cited a thesis done by Carlos Villanueva which studied the implications of the various options for end effects. Since there is no agreement on the way in which end effects should be handled, M.I.T. felt that options should be provided for the user rather than providing a single type of end effect consideration.

Stone and Webster stated that the OPTGEN package has a very good system for handling end effects. When reporting the optimal and near optimal solutions, it provides the costs associated with each solution, both with and without the end effects included. This allows the user to see if there are short-term vs. long-term trade-offs between the various solutions. Thus, if one plant were optimal when considering the long-range end effects, but another plan were substantially better in the short run, and not that far off in the long run, then the latter may be selected by the planner as the better plan.

10 - PGE expressed concern over the testing of the EGEAS system. It felt that the use of synthetic utility data for testing would not be adequate and that real utility data should be used in at least one phase of testing of EGEAS. It was agreed that the use of real utility data would require more than a utility providing information to M.I.T. or Stone and

Webster for testing, but that it would involve a considerable amount of time on the part of the utility to perform the testing itself. The problem therefore is: 1) can we find a utility that can afford to put one of its planners on a project to test the EGEAS system, and 2) where does the funding come from for doing this extensive testing.

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        ┌─────────────────────────────┐
        │  MARKET CONDITIONS,         │
        │  DEMOGRAPHIC TRENDS,        │
        │  ECONOMIC INDICATORS,       │
        │  AND CLIMATOLOGICAL DATA    │
        └─────────────────────────────┘
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        ┌─────────────────────────────┐
        │      DEMAND                 │
        │      FORECASTING            │
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MARKET CONDITIONS,
DEMOGRAPHIC TRENDS,
ECONOMIC INDICATORS,
AND CLIMATOLOGICAL DATA

DEMAND
FORECASTING

FORECASTED
LOAD AND ENERGY DEMAND

FORECASTED
LOAD
CHARACTERISTIC

FORECASTED
SYSTEM LOADS

GENERATION EXPANSION
PLANNING

TRANSMISSION
SYSTEM EXPANSION
PLANNING

RATES

CAPITAL COSTS OF
EXPANSION PLANS

CAPITAL COSTS OF
EXPANSION PLANS

RATE DESIGN

SALES
FORECASTING

SALES REVENUES
FORECAST

PRODUCTION COSTING

SYSTEM RELIABILITY INDEX:
EXPECTED COST OF GENERATED ENERGY

REVENUE
REQUIREMENTS

FINANCIAL PLANNING

STANDARD FINANCIAL STATEMENT
RATE OF RETURN ON INVESTMENT
EARNINGS PER SHARE

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NOTES OF CONFERENCE

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM
ELECTRIC POWER RESEARCH INSTITUTE

Held in the offices of
Southern Services Company
Birmingham, Alabama

November 8, 1979

Present for:

Southern Services Company	Mr. Sam Daniel Supervisor, Generation Application (870-6138)
	Mr. R. Sam Shepard Supervisor, Generation Expansion (870-6642)
	Mr. James C. McNeely Generation Expansion (879-6121)
	Mr. Fred Williams* Manager, Generation Planning (870-6644)
Massachusetts Institute of Technology (MIT)	Dr. Richard D. Tabors Manager, Utility Systems Program (Principal Investigator)

PURPOSE

Task 1-A Analysis of Utility Requirements

The purpose of this meeting was to discuss the present and planned expansion, operating and financial modeling capabilities and practices of Southern Services Company. In addition, the purpose was to discuss the EGEAS structure and solicit information, experience and recommendations relative to its development.

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*Present only at initiation of meeting.

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SUMMARY OF DISCUSSION

1. MIT presented an introduction to the EGEAS structure and answered specific questions concerning the status of present work and modeling capability.

2. Modeling Capability at Southern

Southern Services Company maintains a set of planning models which range from their MIX model adapted and largely rewritten from WASP I to a corporate model currently undergoing final field testing. These models are summarized below and summary statements of their capability are attached to these notes.

o Probabilistic Production Costing Program: Estimates

Operating cost of generating units within utility in meeting forecasted load demand. Includes automatic maintenance schedules. May be run for 2 week periods or divided into four day types: peak day, valley day, Saturday, and Sunday.

o Dynamic load modeling program: Service program used to develop annual forecasted chronological load demand models for use in other system planning programs.

o Loss of Load Probability (LOLP) Program: Determines the reliability of a prescribed generating system using a single area loss of load probability method.

o Generation Mix Planning Package: Adapted from WASP I to evaluate alternative generation from three perspectives: reliability/reserve; operating cost and investment.

o Corporate Model: (Currently being field tested) to allow for the rapid analysis of corporate policy issued; for us in detailed expansion planning. Additional inforation presented here as no summary is available at the present time.

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BASIC STRUCTURE:

Inputs:
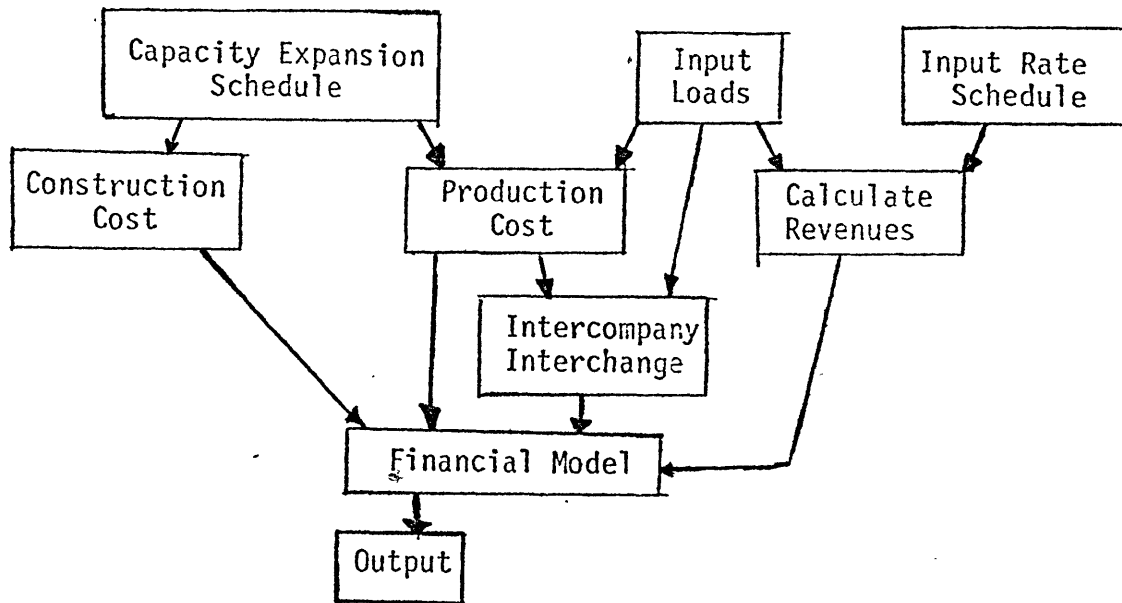
Summary of Status: The model was develsoped in APL and currently is in use in Georgia Power and Gulf Power. Potential user concerns have expanded the level of detail required to make the model data base extremely large and therefore, the operation costly. The original modeling desire of 1 hour turn around is now in excess of a day with intent of reducing it to this level. The financial model appears highly useful in level of detail.

o Other financial models. The corporation maintains a detailed financial model disaggregated to each of the companies which can be aggregated to the four company area. Data inputs are:

    Capitalization rates
    Cost of money by component
    AFUDC
    Tax rates
    Revenues by major rate classes (2-5)

In order to:

    Calculate rate requirmenets to reach target return on common stock

or

    explicit rate of relief allowed

To arrive at:

    coverages

o An engineering economic model is also maintained to calculate the levelized cost of fuel and capital for individual facilities which then become the inputs to the MIX program.

3. Southern Services model use flow.

1. Build expansion plan
2. Production cost run
3. Cost Estimation – Plant, Transmission, etc.
4. Financial planning model including intercompany capacity and energy exchange
5. Output of position of each of four companies plus parent with full financial details. Normally updated three times/year and covering 15-year planning horizon.

The above structure tends to be unidirectional. Generation planning operates with explicit and implicit constraints which act to screen expansion alternatives. An example would be their inability to finance a nuclear power plant at the present time.

4. Suggested considerations for EGEAS financial modeling capability.

o Include explicit capital constraint at least for first 5 to 10 years of model horizon.

o Flexible treatment o CWIP.

o Ability to set coverage constraints (a particular concern of holding companies such as Southern).

o   Information to calculate earnings per share.

o   Level of external financing required.

5. Desirable EGEAS Characteristics

o   Development of common data base for access by multiple planing and
    operating model structures. Southern currently utilizes more than
    four interlinked models not accessing a common base. This leads to
    time and accuracy/consistency losses.

o   For storage representation the Booth Baleriaux configuration appears
    sufficient. Comment on the Schweppe storage paper will be
    forthcoming. Must consider limited pumped hydro.

o   Hydro: Because little, if any, new hydro will be constructed, this
    need not be seen as a tight constraint on the capacity expansion
    planning framework.

o   Environmental/Siting: Southern Company is interested in extending
    the generic siting potential of GEM but not necessarily the
    Brookhaven type of analysis. The concern is with the potential for
    prescreening and then the identification of a limited (less than 25)
    well and carefuly defined expansion alternatives.

o   Input data analysis capability that will ease process for
    - Identifying errors in input data.
    - Identifying assumptions in input data from diverse sources
      such as, for instance, assumed fuel price escalation.
    - Containing a flexibible data editing routine which automatically
      checks for consistency - this should include data range check but
      not hard wired ranges.

o   Size specification for all parameters whould be a variable to allow
    for dimension changes (question: is this acceptable under ANSI
    FORTRAN standards)

o For sensitivity and uncertainty analyses the most significant
variables are:

    fuel price
    fuel availability
    construction cost
    cost of capital
    availability of plant
    load
    environmental regulations

6. The model should be able to handle both limited energy facilities <u>and</u>
fixed energy facilities, i.e., a facility with a guaranteed, fixed,
flowing supply such as guaranteed, pipelined coal or SRC.

7. Expansion models using different algorithms will yield different but
explicable results.

8. Additional information on "fast" LOLP may be found in the work of Dr.
Oliver S. Yu of Commonwealth Edison.

9. Southern has had considerable experience in working with Fourier
Transform Expansion and load curves and are willing to share that
information. The contact is James McNeely.

NOTES OF CONFERENCE

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM
ELECTRIC POWER RESEARCH INSTITUTE

Held in the offices of
Public Service Gas and Electric
Newark, New Jersey

December 5, 1979

Present for:

Public Service Gas and Electric	William Wood, Manager Power Supply Planning System Planning Department
	Andrew C. Johnson Principal Engineering Electric Planning Department
	Dr. Murty P. Bhavaraju Principal Engineer Electric System Technology
Massachusetts Institute of Technology (MIT)	Prof. Fred C. Schweppe Co-principal Investigator
	Dr. Richard D. Tabors Co-principal Investigator

PURPOSE

Task 1-D Review of Other Models

The purpose of the initial meeting was to discuss the present and planned expansion, operating and financial modeling capability of Public Service Gas and Electric. In addition, the purpose was to discuss the EGEAS structure and solicit information, experience and recommendations relative to its development.

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SUMMARY OF DISCUSSION

1. A review of the purpose and structure of the EGEAS package was given
by Tabors and Schweppe to acquaint those individuals from PSG and E who
were not at the kick-off meeting with the purpose of that work.

2. PSG and E currently uses an adapted from of the WASP program
(WASP/SAGE) for their analysis of capacity expansion requirements. They
did not utilize the E.M.A. modeling capability becuase, at the time of
their evaluation, it was too expensive. WASP is used primarily for a
broad-brush solution to PSG and E's capacity planning requirements.
Because it is a single area model, it is difficult to use fully, given
the pooled nature of the system operation.

3. PSG and E, during the late 60's, developed its own production cost
model. This is an hourly simulation, because of an interest in pump
storage. In addition, the model is a two area production cost model, in
which all one thousand generating facilities in the P.J.M. pool may be
analyzed. PSG and E is involved in economy interchanges with the rest of
the pool. The production cost model keeps the company identity while
dispatching a full pool capability.

4. Reliability analysis is undertaken in using standard loss of load
probability modeling techniques based on two area model developed by
General Electric and Baltimore Gas and Electric (GEBGE).

5. Pool planning is done by individual companies given a reliability
constraint set by a pool-wide committee. There is no planning associated
with the pool, only operations and engineering. Reliability is set two
years ib advance based on three criteria; a) fixed outage rate, b) load
shape, and c) large units (this is generally inoperative as it is set at
1300 megawatts which does not exist in the system).

6. The long-range planning is done with a set of models developed at PSG
and E but rationalized by Planmetrics. These models require a committee
interaction to bring together each individual component from planning,

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finance, and operations. The use of this model is directed by the executive vice-president for corporate planning who has no direct staff, but rather draws upon the individual line staffs. As a result, the coordination between finance and planning is extremely high.

7. Uncertainties in the corporate model are handled exogenously, both on the fuel side and on the operating side. The fuel supply department takes care of estimates of fuel cost into the future.

8. The need for advanced capability in analysing load management and new energy technologies was stressed. The issue arose that PSG and E will be more concerned in the near and mid terms with efficient operation of available capacity rather than with the addition of new capacity. This includes the optimization of operations of existing plants through fuel switching as well as the modification of load through a series of available load modification tools. PSG and E has developed a model called ELCS which allows them to analyze customer demand by customer class on an hour-by-hour basis. This work, when carried out over a 30-year period, allows the planners to evaluate a set of load management tools within the utility. The utility's needs for new commitment are well defined out through 1985-1990. Most of their planning will be spent on analysis of future demand, possibly on consideration of cogeneration in their large customers, and some consideration of generation technologies such as garbage burning. Through this, however, load management, both through economics, such as time-of-day metering and through macro- and micro-shedding appear to be a major interest.

NOTES OF CONFERENCE

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM
ELECTRIC POWER RESEARCH INSTITUTE

Held in the offices of
Idaho Power Company
Boise, Idaho

December 7, 1979

Present for:

Idaho Power Company   Mr. James E. Brett
                                       Generation Planning Engineer

                                       Mr. Michael E. Prendergast
                                       Director of Corporate
                                       Analysis

Massachusetts Institute of   Mr. Edward J. Moriarty
Technology (MIT)   Research Staff

PURPOSE

Task 1-A Analysis of Utility Requirements

The purpose of this meeting was to discuss the present and planned expansion, operating and financial modeling capabilities and practices of Idaho Power, and to solicit information, experience and recommendations relating to the proposed EGEAS structure.

SUMMARY OF DISCUSSION

1. M.I.T. acknowledged the receipt of a copy of an internal memorandum discussing the specifications for a General Planning Model which would address the needs of Idaho Power.

2. M.I.T. gave Idaho Power a copy of the SYSGEN paper and documentation, a copy of the ELECTRA documentation, and a copy of the technical portions of the EGEAS proposal.

3. Discussion followed the agenda focusing first on the nature of the optimization techniques, primarily the Dynamic Programming Approach.

4. Idaho Power uses an internal load forecasting methodology which is based on an assume rate forecast. This load forecast is then given to the expansion generation department where a prespecified mix methodology is used to come up with the best expansion plan. The Planmetrics GPOS program is then used for the corporate modeling. A check is then performed to see if the rates used in the load forecasting methodology are consistent with the rates required to implement the given expansion plan as determined in GPOS. If they are not consistent then the entire process must be repeated. The production cost model used for expansion planning is deterministic and based on monthly energy load and peak loads.

5. The Idaho Power system is 75 percent hydro by energy and 1100 megawatts of the 1600 megawatts is hydro. The operation of Idaho Power's hydro power is constrained by many river flow regulations (e.g., minimum hourly flow, maximum rate of change of flow—both plus and negative, downstream navigability, etc.).

6. Financial modeling at Idaho Power was then discussed. A list of definitions used in financial/accounting modeling, sample problems worked out and a sample computer output for one of these problems were provided by Idaho Power.

7. Idaho Power expressed interest in having the following features/capabilities in EGEAS:

o   To measure reliability of a utility which is energy constrained standard LOLP calculations are not sufficient. Some measure such as energy margin is needed (or expected unserved energy).

o   For hydrosystems such as Idaho Power any planning tool must use time periods not greater than a month for analysis since the nature of systems operation varies greatly with hydro availability.

o   The ability to interface with corporate modeling and load forecasting is very important. Rate assumption consisting throughout the entire methodology can be one major benefit of such interfacing.

NOTES OF CONFERENCE

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM
ELECTRIC POWER RESEARCH INSTITUTE

Held in the offices of
North East Utilities
Hartford, Connecticut

January 3, 1979

Present for:

Mr. Brian E. Curry
Generation Planning Expansion X5164

North East Utilities

Mr. Robert W. Goodrich
Senior Scientist
(203) 666-6911, X5159

Mr. Frank Sabatino
Generation Planning Engineer
            X5824

Mr. Peter Shanley
Generation Planning Engineer

Mr. A.P. Sternberg
EHV Transmission, Planning
Manager   X5215

Mr. John Amalfi, Generation
Planning, Associate Engineer
            X5854

Mr. James R. Shuckerow, Jr.
Generation Planning Engineer
            X5170

Mr. William A. Ryan
Generation Planning Engineer
            X5164

Massachusetts Institute of
Technology (MIT)

Prof. Fred C. Schweppe
Director, Utlity Systems
Program

Dr. Michael Caramanis
Utility Systems Program

PURPOSE

Task 1-A Analysis of Utility Requirements

The purpose of this meeting was to discuss the present and planned
expansion, operating and financial modeling capabilities and practices of
North East Utilities, and to solicit information, experience and
recommendations relating to the proposed EGEAS structure.

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SUMMARY OF DISCUSSION

After a brief description of EGEAS by Prof. F. Schweppe, the following points were brought up and discussed.

- Mr. Ryan questioned the purpose of creating still "another" capacity expansion model and pointed out that existing non-propietary models are hard to use because of poor or nonexisting program documentation. He suggested that EPRI create a bureau (center) to aid wide implementation of EGEAS.

Prof. F. Scheppe agreed about the usefulness of setting up such a bureau and stressed that program documentation of EGEAS shall be very extensive and is intended to absorb a sizable portion of the budget.

- Mr. Curry and Mr. Goodrich stated the following issues whose analysis is important for N.E. Utilities:

o   Capacity choices like nuclear versus large coal units

o   Load management

o   Conservation and fuel switching

o   General ability to study small system changes

o   Financial consideration with feedback to optimizing algorithms, especially the modeling of actual cash flow profiles (rather than using levelized costs) and bond coverage constraints

o   End effects

Finally, they stressed that the detail with which EGEAS models various aspects of concern (capacity expansion choices, financial, load management, etc.), should be compatible and comparable. To elaborate the above point, the over/under model was mentioned as an example of a model

containing very satisfactory financial analysis capability but being unbalanced overall by containing too much definition on one side and too little on another.

- Most of the other attendees representing N.E. Utilities joined the discussion generally supporting the above points and adding the following:

o   The ability to study uncertainties could be very useful. A formal probabilistic model for uncertainty analyses seems to be an appropriate methodology.

o   Single utility capacity expansion studies should be able to utilize a capacity reserve margin, preferably represented as a profile over time.

o   Capacity expansion studies at the pool level should be able to use unserved energy estimates.

- The capabilities and limitations of EGEAS in satisfying the above needs were discussed with the purpose of incorporating the concerns voiced during the meeting into the ongoing model effort of EGEAS, to the extent that project funding allows and official EPRI project management approves.

NOTES OF CONFERENCE

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM
ELECTRIC POWER RESEARCH INSTITUTE

Held in the offices of
New England Electric System
Westborough, Massachusetts

January 7, 1980

Present for:

New England Electric System   Mr. Robert E. Charpentier
                (617) 266-5805 ext. 3133

                Mr. Timothy J. Morrissey
                     ext. 2594

                Mr. George P. Sakellaris
                     ext. 2593

Stone and Webster Engineering   Mr. Ken Hicks
Corporation (SWEC)

Massachusetts Institute of   Prof. Fred C. Schweppe, Director
Technology (MIT)   Utility Systems Program

                Dr. Michael Caramanis
                Utility Systems Program

PURPOSE

Task 1-A Analysis of Utility Requirements

   The purpose of this meeting was to discuss the present and planned expansion, operating and financial modeling capabilities and practices of New England Electric System, and to solicit information, experience and recommendations relating to the proposed EGEAS structure.

SUMMARY OF DISCUSSION

After prof. F. Schweppe's and Mr. Ken Hicks' introduction on the content
and scope of EGEAS and a discussion on the proposed structure of EGEAS
modules, the following points were presented by Mr. R. Bigelow on the
modeling needs of NEES.

o Load Growth Uncertainties

A formal probabilistic model evaluating purchases and sales is likely to
be useful. Management is willing to listen to formal probabilistic model
anaysis.

Uncertainties in other areas, as for example fuel costs, are also issues
whose analysis is of importance to NEES.

o Load management and Conservation

The impact on capacity additions, production cost and system reliability
of load shifting, trash burning, wood burning, small hydro, solar energy
utilization at the end use, etc., are issues that need to be analyzed.

o Storage

The ability of capacity expansion models to deal with storage is
important.

o Reliability

System reliability considerations are only of interest when the analysis
is performed at the pool level. For an individual utility the ability to
model reserve margin is sufficient.

The dispatcher's ability to modify load through voltage regulation,
control over some industrial customers and appeals to the public through
the media, results in an order of magnitude reduction in the actual loss

of load probability over that predicted by probabilistic simulation production models.

The effect of ties on reliability is of interest and further, the inclusion in the modeling logic of the dependency of outages (memory of state during previous hour) is also important.

o Financial

Presently, a corporate model developed by NEES's economic planning group is used for postprocessing of capacity expansion plants utilizing a production costing model. The inclusion of financial considerations in a capacity expansion context would be desirable asuming they are not too complex to model.

o Sensitivity Analysis/Uncertainty

Parametric sensitivity would be adequate for NEES. A formal probabilistic approach to uncertainties would be useful.

NOTES ON CONFERENCE

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

ELECTIC POWER RESEARCH INSTITUTE

Held in the offices of
Southern California Edison
Rosemead, California

January 8, 1980

Present for:

    Southern California Edison   M. Douglas Whyte, Manager
                                        Electric Systems Planning

                                        Aline M. Lew, Planning
                                        Engineer Electric Systems
                                        Planning

    Massachusetts Institute of Technology

                                        Dr.Richard D. Tabors, Manager
                                        Utility Systems Program
                                        (Principal Investigator)

                                        Thomas Dinwoodie

Purpose:

    <u>Task 1 Analysis of Utility Requirements</u>

    The purpose of the initial meetings was to discuss the present and
planned expansion, operating and financial modeling capability of
Southern California Edison. In addition, the purpose was to discuss the
EGEAS structure and solicit information, experience and recommendations
relative to its development.

SUMMARY OF DISCUSSION

The primary discussion durina the meetina at Southern California Edison
focused on the modeling structure currently in use at Southern
California Edison for analyzing both operating and capacity expansion
decisions. Southern California Edison has its own model developed in
the mid-60's which utilizes a chronological loading methodology. The
model basically can be used for either long-term fuel analysis or for
mid-range to long-range fixed pathway expansion analysis. The utility
does not use, at this time, any commercially available capacity
expansion models nor any optimization model. They have used, however,
PROMOD with the other utilities in the power pool for California. They
have also tried OGP, but have not been satisfied with the results. In
addition, they have not used any probabilistic load representation, such
as Booth-Baleriaux, in any of the work done to date.

In a long discussion concerning the availability and use of models
within Southern California Edison, the basic concern of the planners
there, is that the modeling structures used to be acceptable to the
remainder of the utility. This meant that they work with a very
detailed model of the Southern California system, and that they work
with hourly or bi-hourly data.

Much of the analyltical work done by Lew over the last six to twelve
months has been in an analysis of load management and fuel-switching
options for the utility. While this has been a useful activity to the
utility, the method used, hourly simulation over a long periods of time,
has been somewhat torturous. For this reason, they expressed an
interest in analytic methods that would be acceptable to the utility as
a whole, but would make such analyses more straightforward. We
discussed at this stage the strengths and weaknesses of the EGEAS
system, and, as a result, derived some considerable interest in the
potential for that modeling tool.

A second point which was of considerable interest to the Southern
California people was the ability to analyze new energy technologies in

both an operating sense and a capacity expansion sense. Southern
California Edison currently participates in the Barstow Solar Thermal
Electric System experiment, and in the development of a large wind
turbine. Given the current regulatory environment in California, there
is considerable interest in being able, further, to analyze such energy
technologies.

The financial model capability of Southern California Edison is based
upon the Planmetrics model The analyses of the financial work are
shared out among different groups at Southern California Edison, though
the majority of it does not involve the Planning Engineering
Department. As a result, those individuals were less able to discuss
the ramifications of the financial modeling. There was a discussion,
however, concerning inclusion of financial capabilities within the
structure of a capacity expansion model. Here considerable enthusiasm
was expressed for at least a limited reporting analysis.

The meeting ended with a discussion of materials to be sent from M.I.T.
to Southern California Edison for their perusal and further comment.